Business Practice Manual for Market Operations

Version 101.1

Revised: July 1, 2025

Approval History

Approval Date: March 23, 2009

Effective Date: March 31, 2009

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BPM Owner's Title: Director, Operations Readiness

Revision History

Version	PRR	Date	Description
101.1	Draft	7/01/2025	Draft updates for DAME
101	1611 1612 1613	3/26/2025	PRR 1611 Convergence bidding is not permitted on intertie nodes PRR 1612 Stage 2 variable energy resource and aggregate capability constraints limits PRR 1613 Market issue that resources providing regulation were going off automatic generation control early to ramp to new dispatch operating target
100	1597	12/23/2024	PRR 1597 Clarifications to the high sustainable limit
99	1593 1590	12/2/2024	PRR 1593 Change to price correction reporting PRR 1590 Scheduling coordinator responsibilities for FERC 2222 distributed curtailed resources and distributed energy resource aggregation resources
98	1587	10/28/2024	PRR 1587 Process for off grid charging indicator election
97	1577	9/11/2024	PRR 1577 Three unrelated corrections and clarifications

Version	PRR	Date	Description
96	1570 1568 1567 1556 1557	7/1/2024	PRR 1570 Details on new process to establish Wheeling Through Priority as part of the TSMSP project PRR 1568 Clarifying tagging requirements in support of resource sufficiency evaluation Phase 2 Project PRR 1567 Updates to constraints related to the impact of ancillary service awards on state of charge on storage resources PRR 1557 Two minor updates related to multistage generators functionality PRR 1556 Clarification on hybrid dynamic limits submission requirements
95	1552 1547 1541	4/9/2024	PRR 1552 Clarification on Number of Historical Days Used in the Mosaic Quantile Regression PRR 1547 Clarification to ancillary service state of charge constraint and bid cost recovery PRR 1541 Update to allow pseudo-tie resources to be part of co-located aggregate capability constraints
94	1548	3/1/2023	PRR 1548 New process for establishing wheeling through priority
93	1542 1536 1533 1530 1527 1526	11/1/2023	PRR 1526 Addition of a withdrawal limit for scheduling coordinators of battery resources PRR 1527 Changes to automated dispatch system partial accept and T-minus 20 auto approval PRR 1530 Changes to ancillary awards constraints and bidding requirements implemented in energy storage enhancements track 1 PRR 1533 Removal of day ahead economic market priority type PRR 1536 New payment for exceptional dispatches holding state-of-charge PRR 1542 Addition of regulation attenuation factors associated with the state of charge equation with ancillary impact (Emergency PRR, updates 1530)

Version	PRR	Date	Description
92	1521	10/3/2023	PRR 1521 New process to automatically adjust day ahead electronic tags to the match the energy profile to the residual unit commitment final schedule
91	1510	7/27/2023	PRR 1510 Clarifications regarding use-limited resources
90	1497, 1501, 1505	6/29/2023	PRR 1505 Refinements to penalty pricing improvements identified from last summer PRR 1501 Updates details and requirements for hybrid dynamic limits PRR 1497 Interchange tagging changes related to resource sufficiency evaluation enhancement phase 2 project.
89	1473	4/6/2023	PRR 1473 Updates for Flexible Ramp Deliverability
88	1471	2/24/2023	PRR 1471 Updates that support the Hybrid Resource Phase 2b project including ACC Constraint structures, market processes, Dynamic limits, examples and diagrams.
87	1478	1/31/2023	PRR 1478 Removal of 50% spinning ancillary service procurement requirement
86	1466	12/5/2022	PRR 1466 Changes for Reliability demand response resource enhancements Phase 2
85	1462, 1463	10/26/2022	PRR 1462 Change to loss sensitivity calculation PRR 1463 Clarification on reference buses used in the market power mitigation
84	N/A	9/6/2022	Returned missing Sections 6.6.1 IFM Inputs and 6.6.2 IFM Constraints & Objectives that were inadvertently removed with PRR 1411
83	1445	8/25/2022	PRR 1445 Updates to the list of acceptable use limitations, clarifications to the calculation of opportunity cost adders for use-limited resources
82	1441, 1433, 1432	6/29/2022	PRR 1441 Ramp rate limitation for certain inverter-based resources PRR 1433 Enforcement of aggregate capability constraints PRR 1432 Addition of 15 interval threshold to regulation service minimum performance testing

Version	PRR	Date	Description
81	1413, 1415, 1429	6/1/2022	PRR 1413 Small updates to align with CAISO move from alert, warning or emergency notice staged alerts to NERC EEA emergency language PRR 1415 Change to short and long start definitions PRR 1429 Guidance for scheduling coordinators to register high priority wheels
80	1404,1406, 1411	5/27/2022	PRR 1404 Market operations BPM edits related to energy storage and distributed energy resources phase 4 cleanup PRR 1406 Activation of minimum constraint in real time dispatch PRR 1411 Update to penalty prices used to determine when the security constrained unit commitment and security constrained economic dispatch software will relax an enforced transmission constraint
79	1395	1/25/2022	PRR 1395 Interchange Transactions and E-Tagging related changes
78	1382, 1387	11/17/2021	PRR 1382 Added a new paragraph describing the end of hour state of charge bid parameter in real time market. Also we provided some edits to section 6.5.4 and referenced all DEB related topics to attachment D in MI BPM. Target Date: 11/1/21. PRR 1387 The enhancement of this Hybrid resources phase 2A will focus on how hybrid generation resources can operate within the ISO markets. Targeted for 11/30/2021.
77	1371	10/26/2021	PRR 1371 To address operational concerns during a time a renewable resource is onboarding.
76	1362,1363	08/31/2021	PRR 1362 Changes are due to FERC 831 phase 2 initiative, related to Market threshold logic. Added a new paragraph under section 6.6.5. Effective date is June 15, 2021. PRR 1363 Based on additional feedback from stakeholders, the CAISO is proposing additional revisions to section 7.2.3.6. The revisions reflect the CAISO's expectation that resources will follow their dispatch operating point between dispatch operating targets.

Version	PRR	Date	Description
75	1345, 1348,1359, 1360	08/11/2021	PRR 1345 This change is related to changes to the penalty prices in the load and wheel portion of the summer readiness initiative. PRR 1348 Submitted by WPTF see sec 3.1.3 PRR 1359 Changes to section 6.6.5 due to Summer Readiness initiative related to Load, export, and wheeling priorities. Effective date: July 15, 2021 PRR 1360 Added new sections in Market Operations BPM due to the Summer Readiness initiative related to Load, export, and wheeling priorities. Effective date: July 15, 2021
74	1344	06/29/2021	PRR 1344 This is related to summer readiness initiative focus on reliability demand response dispatch and real-time price impact changes, management of storage resources during tight system conditions, real-time price during tight system conditions. (2.5.5, 2.5.6, 2.5.7)
73	1334, 1337	06/03/2021	PRR 1334 This change is to enforce the requirement that storage resources hold enough state of charge so that they will be able to respond to regulation signals at the awarded level for 30 min in RTM. PRR 1337 This is related to FERC Order 831 compliance filing. This phase of FERC order 831 compliance filing is related to the penalty prices at which the CAISO market will relax market constraints under the increased energy bid cap.
72	1317,1312	3/30/2021	PRR 1317 This is a clarifying language related to fast, medium, and long start for RA bidding obligation. PRR 1312 This change clarifies the expectation under existing tariff that all resources follow their Dispatch Operating Point (DOP).
71	1303	2/1/2021	PRR 1303 Changes related to IDS.
70	1313	12/23/2020	PRR 1313 This is a clean-up related to the language in section 2.5.5. This was missed during the implementation of PRR 1136.

Version	PRR	Date	Description
69	1288	12/17/2020	PRR 1288 This enhancement is to allow individual resources, with potentially different SCs and technologies, to share a common point-of-interconnection (POI) to the transmission grid. Effective date; by 1/15/2021. Phase 1 is for Co-located resources only.
68	1278	10/28/2020	PRR 1278 The ISO has implemented several improvements to the Non-Generator Resource (NGR) Model in the day-ahead and real-time market. The PRR document provides detailed information regarding the changes applied to the market model. Effective Date: 8/27/2020
67	1246,1270, 1274, 1282	10/12/2020	PRR 1246 This update is related to part 3B of energy storage and distributed energy resource (ESDER) multi-phased initiative that allows the renewable resources to participate more efficiently in the market. PRR 1270 With the upgrade of the ADS platform, few enhancements that provide both operational and market efficiencies were added. The detailed enhancements are documented in the Business Requirement Specification, and the impacts to Market Operation due to these enhancements are included in this PRR. PRR 1274 This improvement is to address the flexible ramping product issues related to ramping capacity that can be dispatched in subsequent market runs to cover range in the forecasted net load. PRR 1282 (Emergency) The changes are to improve the scheduling of resources in the RUC and real-time process based on expected priorities for exports. Effective date: 9/5/2020.
66	1257, 1258	08/26/2020	PRR1257 This update is due to Commitment Cost Enhancements Tariff Clarifications initiative. One of the main drivers in this update is to provide definition for run-of-river resources and list the registration process. The effective date will be July 1, 2020. PRR1258 The penalty prices for Western Imbalance Energy Market incremental flow and Western Imbalance Energy Market area total flow constraints will be revised to align them with the WEIM Entitlement Rate of change constraints. This is effective 6/17/2020.

Version	PRR	Date	Description
65	1221, 1222, 1224	03/26/2020	PRR1221 This is a clarification to the E-Tag adjustment and curtailment rules as requested by market participants. PRR1222 This is to add a settlement process on a manually procured Ancillary Services that do not start or end on a 15-minute boundary. PRR1224 This change reflects the market enhancement to enable Variable Energy Resources to offer Ancillary Services in the ISO markets. **Additional administrative work: Deleted the Addendum at the end of this BPM and transferred the related language to the body of the BPM since FERC order made the remaining Aliso Canyon changes permanent.
64	1210	01/29/2020	PRR1210 Provide an additional method for satisfying the Regulation recertification requirement in the event of a resource's failure to meet the minimum performance threshold for one or more months of a calendar quarter. Miscellaneous changes related to HASP timeline: Few years back, we moved the HASP start-up timeline to 71.5 minutes before the trading hour. This is an update to section 7.1.1 and 7.6 to reflect the correct time.
63	1176,1180, 1191,1194	10/28/2019	PRR1176 Changes to the bid dispatchable option from ESDER3A project. PRR1180 Revision to paragraph 2.1.3 due to the changes to enable storage resources with a capacity rating of 100KW to participate in the CAISO markets, this is related to FERC 841. Effective date: Fall 2019. PRR1191 These changes are to support the Local Market Power Mitigation Enhancements 2018 Project (LMPME). These changes include mitigation process enhancements due to flow reversal and economic displacement. Effective date: November 2019. PRR1194 Changes due to reliability must run and capacity procurement mechanism enhancement project.

Version	PRR	Date	Description
62	1167, 1162	09/09/2019	PRR1167 This revision is based on the Tariff clarification amendment filling section 42.1.5 to state that the CAISO may also enter into real-time contracts for unloaded resource capacity to meet Applicable Reliability Criteria. This clarification is consistent with the existing business practices. PRR1162 This is a language update as the functionality already exist. Updates include removing the Demand Curve Cap from Figure 2 and add it to the Real Time Market Parameter table. Also, updating language to reflect that uncertainty requirements are calculated off the 97.5th percentile and 2.5th percentile of one histogram, rather than separate histograms for FRU and FRD. This is already been in effect.
61	1156, 1170	08/07/2019	PRR1156 The WEIM Upward Available Balancing Capacity Range penalty price will be revised from 1100 to 1050 to align it with the power balance constraint penalty price to dispatch ABC up capacity for WEIM entity PRR1170 Clarification regarding the interpretation of ISO tariff section 40.6.4.1 which would allow for a limited must offer obligation for certain types of resources.
60	1136, 1147, 1108	04/08/2019	PRR1136 The Commitment Cost Enhancements Phase 3 initiative changes the definition of Use-Limited Resources and allows Use-Limited Resources to include opportunity costs in their commitment costs or default energy bids, where applicable. Effective date: April 1, 2019 PRR1147 Due to Commitment Cost Enhancement phase 3 filing, there is an addition of a new resource type called Conditionally Available Resources (CAR). This PRR is to describe this new resource type functionality and rules. Effective Date: 4/1/2019 PRR1108 To improve the current load zones to better align with local loads with more granularity. Effective date: 04/16/2019
59	1119, 1146	02-28-2019	PRR1119 Adding Clarifying language to the Market Operations BPM on the resource's outage treatment on startup. PRR1146 this is to clarify the locational marginal prices in section 3.2 based on a Tariff clarification.

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58	1087, 1095,1111	11-29-2018	PRR1087 - This is to enhance the Day Ahead and Real Time markets to represent constraints impacted by generator contingencies and Remedial Action Scheme (RAS) operation within the market by modeling the generation/load loss in the dispatch, and the transmission loss along with subsequent generation/load loss due to RAS operation in the dispatch.(Effective 2/1/2019) PRR1095 - Policy change in methodology for recertification for this BPM section. PRR1111 - Due to the extension of Aliso Canyon Tariff provisions. CAISO will extend the temporary measures beyond December 16th, 2018. Miscellaneous correction.
57	1053	05-24-2018	PRR 1053: This revision is to further clarify the flexible ramping product requirement thresholds.
56	1048	04-24-2018	Relocated the Dynamic Competitive Path Assessment (DCPA) formula details in section 2.1.13 to Market Operations Appendices BPM section B.1.2
55	1036	02-13-2018	• Due to the extension of Aliso Canyon Tariff provisions. CAISO will extend the temporary measures beyond November 30th, 2017. • Created section 8.0 for E-Tagging that moved Post Market Activities to a new Section 9.0 • Updated section 7.2.2, 7.2.2.1 to reference section 8.0 Additional miscellaneous updates to paragraphs 2.1.13, 7.2.3.4 & 7.8.2
54	1015	10-30-2017	As part of Market & Operational Excellence, the controllable devices (i.e. phase shifters) market setup and optimization features were added to the markets.
53	991	07-13-2017	PRR 991 Changes to reflect the new tariff requirements and new policy on Administrative pricing. • Effective May 2, 2017
52	985	05-31-2017	PRR 985 The first change is to reduce the amount of power balance constraint relaxation for over-supply conditions. The other two changes are updates due to additional WEIM entities; and deletion of penalty prices related to flexible ramp constraint which is no longer in place after the implementation of the flexible ramping product. Effective date for the power balance relaxation constraint is April 10th.

Version	PRR	Date	Description
51	953, 945	02-02-2017	PRR 953 Due to Aliso Canyon phase 2 gas-electric coordination initiative and the interim tariff revisions from December 1, 2016 through November 30, 2017. Effective date December 1, 2016 PRR 945 To improve the accuracy of market power mitigation for 5-minute real time dispatch market. Effective date is March 1, 2017. Miscellaneous corrections
50	921, 938	10-07-2016	PRR 921 Added changes for ESDER1 for NGR Enhancements for DA Starting SOC and NGR Option to not use Energy Limits or SOC in optimization. Sections 2.1.1.3, 2.1.13.1,4.6.1,6.6.2.3,7.1,7.8.2.5 PRR 938 additional edits due to the Flexible Ramping Product initiative. Effective date 11/1/2016
49	935	09-12-2016	PRR 935 changes related to the Pricing Enhancement policy
48	909, 917, 918, 887	09-01-2016	PRR 909 Adding Addendum due to Aliso Canyon gas-electric coordination initiative and the interim tariff revisions. PRR 917 improving the accuracy of RTM power mitigation procedure. PRR887 Transfer ULR information from Reliability Requirement BPM.
47	906	07-19-2016	PRR 906 Added new section 6.6.1.1.1 for MLC adjustment under Pmin re-rate
46	894	06-17-2016	PRR 894 Penalty price parameters adjustment due to ABC functionality. Also added correction to paragraphs 4.6.3 & 4.2.7
45	869	11-24-2015	PRR 869 Scheduling priority for transmission rights update. Section 5.1.9
44	847	07-06-2015	PRR 847 for clarification/adjustment on the penalty price values
43	754	02-19-2015	*This change was missed from the previous update PRR 754 Changes in support of RDRR initiative. Changes made to sections 2.1.2, 4.6, 7.1, and 7.11.1
42	778/805 806/810 811/813	12-11-2014	PRR 778 change SLIC to outage management system PRR 805 for Pay for Performance Enhancement PRR 806 for Nodal Group Limit Constraint changes PRR 810 Change CMRI to Customer Market Results Interface PRR 811 MSS elections & participation change PRR 813 Addition of flexible ramping constraint penalty price

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41	750/789	09-30-2014	PRR 750 for FNM expansion, PRR 760 for SC self-certification (section A13), and PRR 781 for FERC order 789
40	733/738	05-01-2014	PRRs 733 & 738 Penalty price changes
40	736	05-01-2014	PRR 736 Updating content to provide additional clarity and to reflect lessons learned since original implementation of Attachment G.
40	747	07-09-2014	PRR 747 This change to the penalty price for over-procurement in RUC is to allow RUC to relax the power balance when RUC procurement is higher than the Demand forecast
39	732/764	05-06-2014	PRR 732 was added as an emergency for the purpose of order 764, changes were made to section 7.10.4
39	734/735	05-06-2014	PRRs 734 & 735, changes made to attachments A,B,E,F,H,I
39	716/733	05-06-2014	PRR 716, corrections were initially made, then PRR 733 was created on an emergency basis for further clarification, corrections made to section 6.6.5
39	704	05-06-2014	PRR 704 FERC order 764
39	702	05-06-2014	PRR 702 Price correction changes
38	695	01-6-2014	PRR 695-Corrections Clarifications 2013. Changes made to sections 2.5.2.1 and 6.1.7.
38	696	01-6-2014	PRR 696-Minimum Online Commitment Constraint. New section 6.6.2.4 added.
37	684	10-02-2013	PRR 684 - Change multi-stage generator (MSG) transition rounding method in Day-Ahead market. Changes made to section 4.5.
36	663	07-03-2013	PRR 663 - Modify transmission constraint relaxation parameter. Changes made to section 6.6.5.
36	673	07-03-2013	PRR 673 - Pay for performance regulation – clarifications. Changes made to sections 4.3.1, 4.6.1, and Appendix Attachment J section J.3.
35	657	06-04-2013	PRR 657 - pay for performance regulation. Changes made to sections 2.5.2, 4.1.1, 4.2.1, 4.2.6, 4.3.1, 4.3.2.1, 4.4, 4.6.1, 6.1.4, 6.6.1.1, 7.2.3, 7.2.3.2 and 7.6.4. New Appendix Attachment J added.

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34	651	05-03-2013	PRR 651 - Local market power mitigation implementation phase 2. Changes made to sections 2.3.1.1, 2.3.2.1, 6.5.3, 6.7.2.7, 6.7.4.2, 7.4, 7.5.4, 8.1.2, and Appendix Attachment B sections B.1 and B.2. New section 7.4.1 added.
34	652	05-03-2013	PRR 652 - Multi-stage generation enhancements phase 3. Changes made to section 2.1.5, 7.6.3.3 and Appendix Attachment D sections D.7.4 and D.7.5.
34	653	05-03-2013	PRR 653 - Price inconsistency market enhancements. Change made to section 3.1.5.
34	655	05-03-2013	PRR 655 - Treatment of Market Participants with Suspended Market-Based Rate Authority. Change made to section 6.7.2.7.
33	644	04-05-2013	PRR 644 - Marginal Cost of Losses - Inside CAISO Grid But Outside CAISO BA. New Appendix Attachment I added.
32	639	03-12-2013	PRR 639 - Circular Scheduling. Changes made to Appendix Attachment F. New section F.4 added. New Appendix Attachment H added.
31	630	02-11-2013	PRR 630 - Electronic communication of ELC instructions from RUC. Change made to section 6.8.
31	632	02-11-2013	PRR 632 - Conform setting feasibility adjustment. Change made to section 7.5.2.
31	635	02-11-2013	PRR 635 - RTUC advisory solution and clarification to market disruption. Changes made to sections 7.6.4, 7.8.3, 7.10.4, 7.10.4.1 and 7.10.4.2.
30	611	01-09-2013	PRR 611 - Real-time market parameter change. Change made to section 6.6.5.
29	597	12-10-2012	PRR 597 – Changes to support flexible ramping settlement. Change made to section 7.1.3. New section 7.1.3.1 added.

Version	PRR	Date	Description
28	559	11-12-2012	PRR 559 - Update Market Power Mitigation process description in BPM. Changes made to sections 6.5.3.1, 6.6.5, and Appendix Attachment B, sections B.2.1.1 and B.2.2.
28	560	11-12-2012	PRR 560 - Changes to support grouping constraints initiative - part II a. Change made to section 2.1.6.1.
28	561	11-12-2012	PRR 561 - Revise description of real-time load forecast software. Change made to section 7.8.1.3.
28	563	11-12-2012	PRR 563 - Changes to Expected Energy algorithm to incorporate non-generator resources. Changes made to Appendix attachment C, sections C.1, and C.2.
28	568	11-12-2012	PRR 568 - Changes to consideration of minimum load costs and initial conditions. Changes made to sections 6.1.9, 6.6, 7.1, and 7.3.1.3.
28	571	11-12-2012	PRR 571 - Contingency dispatch enhancements part 1. Change made to section 7.9.
28	575	11-12-2012	PRR 575 - Modify system power balance constraint parameter. Change made to section 6.6.5.
28	584	11-12-2012	PRR 584 - Contingency dispatch enhancements part 2. Changes made to sections 7.9 and 7.9.3.
28	586	11-12-2012	PRR 586 - Changes to support non-generator resources and regulation energy management. Changes made to sections 4.6.1, 6.5, 6.6.2, 7.1, 7.5.1 and 7.6.3.1. New sections 2.1.13, 2.1.13.1, 6.6.2.3 and 7.8.2.6 added.
27	550	06-06-2012	PRR 550 - Changes to support Transmission Reliability Margin functionality. Changes made to sections 2.3.1, 2.5.2.4.1, 4.2, 5.1.5, 5.1.7, 5.1.9, 5.1.11, 5.2.1, 5.2.2, 5.2.3, 6.1.6, 6.1.7, 6.4.2, 6.4.4, and 7.1
26	546	05-07-2012	PRR 546 - Remove RDRR language from BPM for Market Operations. Changes made to sections 2.1.2, 4.6, 6.7.2.7, 7.1, and 7.11.1

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25	532	04-09-2012	PRR 532 - Changes to support local market power mitigation enhancements. Changes made to sections 2.3.1, 2.3.1.1, 2.3.1.2, 2.3.2.1, 2.3.2.2, 2.4.5, 6, 6.2, 6.3.1, 6.4.5, 6.4.6, 6.5, 6.5.1, 6.5.2, 6.5.3, 6.5.5, 6.6, 6.6.5, 6.7.2.6, 6.7.2.8.1, 7.2.1, 7.3.3, 7.4, 7.9, Appendix Attachment B, sections B and B.1 through B.12, Appendix Attachment C section C.2.1.1.25, and Appendix Attachment D sections D.3.1 and D.6.1. New sections 6.5.3.1 and 6.5.3.2 added.
25	535	04-09-2012	PRR 535 - Changes to support Multi-stage generation enhancements functionality. Changes made to sections 2.1.5 and 6.6.2.
24	523	03-08-2012	PRR 523 - MSG Enhancement Dec 2011. Change made to section 7.6.3.3.
24	526	03-08-2012	PRR 526 - Miscellaneous PIRP related changes. Changes made to Appendix Attachment A, sections A.13.6.1 and A.13.6.5.
23	495	12-09-2011	PRR 495 - Changes in support of Flexible Ramping Constraint initiative. New section 7.1.3 added.
22	479	10-28-2011	PRR 479 - Changes to support the 72 hour RUC initiative. Changes made to section 2.3, 2.3.1.3, 2.3.1.4, 6.4.7, 6.7 and subsections, 6.8, and 7.7.
22	482	10-28-2011	PRR 482 - Changes to support grouping constraints initiative. Change made to section 2.1.6.1. New section 6.6.2.2 was added.
22	483	10-28-2011	PRR 483 - Changes to support interim dynamic transfer functionality. New section 7.8.2.5 was added.
22	485	10-28-2011	PRR 485 - Clarify telemetry requirements for Eligible Intermittent Resources. Changes made to appendix Attachment A, sections A.13.2.2 and A.13.3.3.
21	454	09-19-2011	PRR 454 - Changes in support of RDRR initiative. Tariff effective 4/1/12. Changes made to sections 2.1.2, 4.6, 6.5.1, 6.7.2.6, 7.1, and 7.11.1

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20	443	08-12-2011	PRR 443 - Market Ops companion changes to support new Direct Telemetry BPM. Changes made to appendix attachment A, section A.13.
20	445	08-12-2011	PRR 445 - Virtual Bidding -- Interties With Zero ATC. Changes made to section 2.5.2.4.1 and 6.4.4
19	426	06-13-2011	PRR 426 - Forbidden Operating Region Compliance Feature. Changes made to section 7.2.3.7
18	385	05-18-2011	PRR 385 - Open/isolated intertie handling companion language for Market Operations BPM. Detail provided in Market Instruments BPM. Changes made to sections 6.4.4 and 7.1
18	420	05-18-2011	PRR 420 - Cleanup of sections 2.4.2.2 and 6.1.2. These sections changed to reflect most recent information.
17	360	04-01-2011	PRR 360 - Market Ops - Clarification of Power Balance Constraint Parameters. Entry added to Real Time Market Parameters table in section 6.6.5.
17	375	04-01-2011	PRR 375 - RUC Availability bids for RA resources - conform Market Ops language to Market Instruments. Changes were made to section 6.7.2.6
17	378	04-01-2011	PRR 378 - Change market parameter value for Ancillary Service Maximum Limit. An entry was changed in both the Integrated Forward Market (IFM) Parameter Values table and the Real Time Market Parameters table in section 6.6.5.
17	421	04-01-2011	PRR 421 - Change market parameter values to reflect increased bid cap. Multiple entries were changed in both the Integrated Forward Market (IFM) Parameter Values table and the Real Time Market Parameters table in section 6.6.5.

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16	342	01-26-2011	PRR 342 - Market Operations BPM changes in support of convergence bidding. Changes were made to sections 2.1.2, 2.2.1, 2.2.3, 2.2.4, 2.3.1, 2.3.1.1-2.3.1.3, 2.3.2, 2.4.5, 2.5.2, 3.1, 3.1.4, 3.2.4, 6.1.3, 6.1.8, 6.3.1, 6.4.4, 6.4.6, 6.5.1, 6.6, 6.6.1.1, 6.6.3, 6.6.6, 6.6.7, 7.1, 8.1.5.4 and appendix Attachments D and E. New sections 2.5.2.4, 3.1.10, 6.6.5.4, and appendix Attachment F were added.
15	349	12-21-2010	PRR 349 - Changes for Market Ops BPM in support of revised Scarcity Pricing Proposal. Changes were made to section 4.2. New section 4.4.1 was added.
15	354	12-21-2010	PRR 354 - Implementation of Market Issues process in support of Post Five-Day Price Correction Process. New appendix Attachment G was added.
15	355	12-21-2010	PRR 355 - Initial Condition for Day-Ahead Market Resources. New section 6.1.9 was added.
15	358	12-21-2010	PRR 358 - Clarification of use of minimum effectiveness threshold. Changes were made to section 3.2.4.
14	345/359	12-07-2010	PRR 345 and 359 – Changes related to the Multi-Stage Generating Resource modeling implementation. Changes were made to sections 2.2.1, 2.4.5, 2.5.2, 4.3, 4.3.2, 4.5, 4.6, 6.5.1, 6.6, 6.6.1.2, 6.6.2, 6.6.2.1, 7.2.3.1, 7.2.3.6, 7.3.1.3, 7.5.3.2, 7.6, 7.6.3.1, 7.8.2.2, 7.11, 7.11.1 and appendix Attachments C and D. New sections 2.1.5, 7.6.3.3, 7.6.3.4, and 7.6.3.5 were added.
13	296	10-01-2010	PRR 296 – LDF adjustment due to weather. Changes were made to section 3.1.4
13	297	10-01-2010	PRR 297 – Post five-day price correction process. Changes were made to section 8.
13	301	10-01-2010	PRR 301 – Clarification of MSS election options. New section 2.4.2.3 was added.
12	281	09-14-2010	PRR 281 – Wheeling out and wheeling through transactions. Changes were made to section 2.5.2.2

Version	PRR	Date	Description
11	167	08-09-2010	PRR # 167 - Market Operations BPM changes related to PDR. Changes were made to sections 2.1.2, 2.4.4, 2.4.5, 2.5.2.1, 2.5.2.3, 4.1.1, 4.2.1, 4.6, 4.6.3, 6.5.1, 7.4, 7.8.1.2
10	276	7-26-2010	PRR # 276 - Detail related to Eligible Intermittent Resources (EIRs). Changes were made to Appendix A sections 13, 13.2, 13.2.2, 13.3, 13.3.1, 13.3.2, 13.3.3, 13.3.5, 13.5, 13.7; New section 13.4 was added.
9	215	6-15-2010	PRR # 215 - Details related to the Forbidden Operating Region (FOR) implementation. Changes were made to sections 7.8.2.4, 7.10.4 and 7.10.4.1.
8	213	6-1-2010	PRR # 213 - Price Corrections Make Whole Payments. A new appendix E was added.
7	132	5-12-2010	PRR # 132 - Market Operations BPM Updates related to PIRP
7	202	5-12-2010	PRR # 202 - Update hyperlink to market data
6	170	4-15-2010	PRR # 170 - Market Operations BPM changes related to RTM forbidden operating region (FOR) implementation.
5	189	4-1-2010	PRR # 189 - Five-Day Price Correction Time Horizon. Changes were made to section 8.1.6.2 of the BPM.
5	201	4-1-2010	PRR # 201 - Proposed parameter changes for April 1, 2010 Energy Bid Cap increase to $750. Changes were made to sections 2.2.2 and 6.6.5 of the BPM.
5	171	4-1-2010	PRR # 171 - Market Operations BPM changes related to AS in HASP. The following sections were updated :2.3.2, 2.3.2.1 , 2.3.2.2, 2.3.2.3, 4.3.2, 4.5, 7.2.2, 7.2.3.2, 7.3.3, 7.3.4, 7.5, 7.5.4, 7.5.5, 7.5.5.2, 7.6.2. The following new sections were added: 7.6.2.1, 7.9.4.1
4	86	12-31-2009	PRR # 86 – Changes to Market Operations BPM arising out of implementation of Standard Capacity Product. Changes were made to Section 6.6.3 due to

Version	PRR	Date	Description
			implementation of Standard Capacity Product initiative.
4	100	12-31-2009	PRR # 100 - Market Operations BPM changes due to Simplified ramping rules implementation. Changes were made to Section 6.6.2 and Section 7.6.3.2 of the BPM.
4	104	12-31-2009	PRR # 104 - Revisions to ensure consistency with RMR contract and tariff requirements. Changes were made to Section 6.5.1 and Section 6.5.2 of BPM.
3	78	11-02-2009	PRR # 78 – New Expected Energy Calculation Schedule effective with Payment Acceleration. Changes were made to Appendix C Section C.6 due to implementation of payment acceleration initiative.
2	39	10-14-2009	PRR # 39 – Changes were made to Appendix C Section C.4.1 to reflect new expected energy types arising from implementation of new exceptional dispatch codes.
1		3-23-2009	Version Release

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1. Introduction

Welcome to the CAISO ***BPM for Market Operations***. In this Introduction you will find the following information:

- The purpose of CAISO BPMs
- What you can expect from this CAISO BPM
- Other CAISO BPMs or documents that provide related or additional information

1.1 Purpose of CAISO Business Practice Manuals

The Business Practice Manuals (BPMs) developed by CAISO are intended to contain implementation detail, consistent with and supported by the CAISO Tariff, including: instructions, rules, procedures, examples, and guidelines for the administration, operation, planning, and accounting requirements of CAISO and the markets. Each Business Practice Manual is posted in the BPM Library at: http://bpmcm.caiso.com/Pages/BPMLibrary.aspx. Updates to all BPMs are managed in accordance with the change management procedures included in the **BPM for Change Management**.

1.2 Purpose of this Business Practice Manual

This *BPM for Market Operations* covers the rules, design, and operational elements of the CAISO Markets. The BPM is intended for those entities that expect to participate in the CAISO Markets, as well as those entities that expect to exchange Power with the CAISO Balancing Authority Area.

This BPM benefits readers who want answers to the following questions:

- What are the roles of CAISO and the Scheduling Coordinators in the CAISO Markets?
- What are the concepts that an entity needs to understand to engage in the CAISO Markets?
- What does a Market Participant need to do to participate in the CAISO Markets?

- What are the market objectives, inputs, and outcomes?

Although this BPM is primarily concerned with market operations, there is some overlap with other BPMs. Where appropriate, the reader is directed to the other BPMs for additional information.

If a Market Participant detects an inconsistency between BPMs, it should report the inconsistency to CAISO before relying on either provision.

The provisions of this BPM are intended to be consistent with the CAISO Tariff. If the provisions of this BPM nevertheless conflict with the CAISO Tariff, the CAISO is bound to operate in accordance with the CAISO Tariff. Any provision of the CAISO Tariff that may have been summarized or repeated in this BPM is only to aid understanding. Even though every effort will be made by the CAISO to update the information contained in this BPM and to notify Market Participants of changes, it is the responsibility of each Market Participant to ensure that he or she is using the most recent version of this BPM and to comply with all applicable provisions of the CAISO Tariff.

A reference in this BPM to the CAISO Tariff, a given agreement, any other BPM or instrument, is intended to refer to the CAISO Tariff, that agreement, BPM or instrument as modified, amended, supplemented or restated.

The captions and headings in this BPM are intended solely to facilitate reference and not to have any bearing on the meaning of any of the terms and conditions of this BPM.

1.3 References

The definition of acronyms and words beginning with capitalized letters are given in the *BPM for Definitions & Acronyms*.

Other reference information related to this BPM includes:

- Other CAISO BPMs
- CAISO Tariff

2. Market Operations Overview

Welcome to the *Market Operations Overview* section of the CAISO *BPM for Market Operations*. In this section, you will find the following information:

- A high-level description of the structure and operations of the CAISO Markets

Subsequent sections "drill down" in greater detail. Included in subsequent sections are the following topics:

- Market activities which consist of:
  - The buying and selling, transmission of Energy or Ancillary Services into, out of, or Wheeling Through the CAISO Balancing Authority; and the allocation of transmission
  - The request or receipt of Congestion Revenue Rights through allocations or auctions

- Products and services that are traded in the CAISO Markets

- CAISO Markets which consist of:
  - Day-Ahead Market, which includes the Integrated Forward Market (IFM) and the Residual Unit Commitment (RUC)

  Real-Time Market processes, which includes the following processes: (1) the Hour-Ahead Scheduling Process, (2) Real-Time Unit Commitment (RTUC), (3) the Short-Term Unit Commitment (STUC), (4) the Fifteen Minute Market (FMM), and (5) the Real-Time Dispatch (RTD).
  - Objectives, inputs, and outputs

- Roles and responsibilities according to market activities

- Market Information, which consists of resource static data, Bids, Inter-SC Trades

2.1 Market Entities

The entities that engage in the operation of the CAISO Markets are described in the following subsections.

2.1.1 CAISO

2.1.2 Scheduling Coordinators

2.1.3 Participating Generators

2.1.4 Constrained Output Generator

A Constrained Output Generator (COG) is a Generating Unit with a zero or very small operating range between its Minimum Load (Pmin) and Maximum Capacity (Pmax).

Generating Units are eligible to elect COG status, on an annual basis, and benefit from the flexible COG model only if their actual operating range (Pmax – Pmin) is not greater than the highest of three (3) MW or five percent (5%) of their actual Pmax. Eligible Generating Units that elect COG status must make an election before each calendar year. Resources with that have zero operating range must participate as COGs. Resources with a non-zero operating range have the option to participate as a COG. The election is made by registering the resource in the Master File as having a PMin equal to PMax less 0.01 MW (PMin+ PMax -0101 MW) within the time frame for submitting Master File changes so that the change becomes effective by the first of the year. . COGs must also elect the Proxy Cost or Registered Cost option for Start Up and Minimum Load cost, similar to all other Generating Resources. Registered COGs may submit an Energy Bid to indicate participation in the market for the relevant Trading Hour. The submitted Energy Bid will be replaced by the CAISO with a Calculated Energy Bid determined by dividing its Minimum Load Cost by MW quantity of the resources PMax. COG may not bid or self-provide Regulation or Spinning Reserve, but they may be certified for Non-Spinning Reserve or Imbalance Reserve. Registered COGs may also self-schedule at their Pmax. COGs are not eligible to submit RUC bids or received compensation for any RUC Awards.

2.1.5 Multi-Stage Generating Resources

2.1.6 Participating Loads

2.1.7 Non-Participating Loads

2.1.8 Utility Distribution Companies

2.1.9 Metered Subsystems

2.1.10 Balancing Authority Areas

2.1.11 Participating Transmission Owners

2.1.12 System Resource

A System Resource is a group of resources, single resource, or a portion of a resource located outside of the CAISO Balancing Authority Area, or an allocated portion of a Balancing Authority Area's portfolio of resources that are either a static interchange schedule or directly responsive to that Balancing Authority Area's Automatic Generation Control (AGC) capable of providing Energy and/or Ancillary Services to the CAISO Balancing Authority Area, provided that if the System Resource is providing Regulation to the CAISO it is directly responsive to AGC. There are different types of System Resources:

1) Dynamic System Resource: A System Resource that is capable of submitting a Dynamic Schedule, including a Dynamic Resource-Specific System Resource. Unless otherwise noted, Dynamic System Resources are modeled and treated in the market similar to Generating Resources.

2) Non-Dynamic System Resource: A System Resource that is not capable of submitting a Dynamic Schedule, which may be a Non-Dynamic Resource-Specific System Resource.

3) Dynamic Resource-Specific System Resource: A Dynamic System Resource that is physically connected to an actual generation resource outside the CAISO Balancing Authority Area.

4) Non-Dynamic Resource –Specific System Resource: A Non-Dynamic System Resource that is physically connected to an actual generation resource outside the CAISO Balancing Authority Area.

2.1.13 Non-Generator Resources

Non-Generator Resources (NGRs) are Resources that operate as either Generation or Load and that can be dispatched to any operating level within their entire capacity range but are also constrained by a MWh limit to (1) generate Energy, (2) curtail the consumption of Energy in the case of demand response, or (3) consume Energy.

More generally, NGRs are resources that operate as either generation or load and can be dispatched within their entire capacity range, inclusive of the generation and load. They are also constrained by an energy (MWh) limit to generate or consume energy on a continuous basis. NGRs include limited energy storage resources (LESR), and Generic resources. By modeling the generation range from negative to positive, the NGR model provides NGRs the same opportunity as generators to participate in the CAISO energy and ancillary service markets subject to meeting eligibility requirements.

NGRs have the following characteristics:

- NGR is a resource that has a continuous operating range from a negative to a positive power injection; i.e., it can operate continuously by either consuming energy or providing energy, and it can seamlessly switch between generating and consuming electrical energy. An NGR functions like a generation resource and can provide energy and AS services. Because of the continuous operating range, NGRs do not have minimum load operating points, state configurations, forbidden operating regions, or offline status (unless on outage). Therefore they do not have startup, shutdown, minimum load, or transition costs.
- The ISO can use its NGR functionality to model a Limited Energy Storage Resource (LESR). However, NGR functionality is not limited to a storage resource. Any resource that can operate seamlessly from negative to positive can use this functionality.
    - For an NGR, the energy limits (MWh) is the maximum or minimum energy the device can store; this energy can be stored in the form of electrical charge, chemical energy, potential energy, or kinetic energy and it can be discharged to generate electricity. Based on an initial stored energy (state of charge (SOC)), the continuous energy consumption or generation is constrained by the maximum or minimum stored energy limit (specified in the Master File), accounting for inherent losses while charging and discharging.
    - For NGRs that elect not to use Regulation Energy Management, the day ahead and real-time markets observe the energy limits in the energy and ancillary service optimizations.
    - For NGRs using Regulation Energy Management, energy limits are observed in real-time economic dispatch only.
    - The energy limits for NGRs are not required for the resource if the resource does not have that physical limitation; nevertheless, if the NGR resource has a stored energy limit, it must register the limit value with the ISO so that the ISO can observe the limit

in the market. When resource energy limits are not provided, the ISO assumes that the NGR does not have these constraints. The resource owner and Scheduling Coordinator must manage any resource energy constraints in order to comply with ISO dispatch instructions in the ISO Market.

- The algebraic power output of a NGR is limited between a minimum and a maximum capacity measured in MW. The minimum or maximum capacities can be negative. The maximum capacity is greater than the minimum capacity. For an NGR, the maximum capacity (positive) represents the MW injected to the grid when it is discharging at its maximum sustainable rate; minimum capacity (negative) represents the MW withdrawn from the grid when it is charging at its maximum sustainable rate.
- NGRs have distinct ramp rates for operating in a consuming mode (charging) or in a generating mode (discharging), but is limited to one segment for each mode.
- NGRs can provide energy and ancillary services (AS).
  - NGRs can provide ancillary services (AS) continuously while they are charging or discharging. The dispatch of a NGR providing AS must employ a stored energy management scheme to manage the state of charge and ensure that there is sufficient stored energy in the device to dispatch to satisfy the AS when they are called upon.
  - NGRs can provide regulation from anywhere within their regulation range.
  - NGRs will be subject to Spin/Non-Spin No Pay based on the resource's energy limit on an after the fact basis.
- Generic NGR model has the ability to generate or consume energy. Market Participants can use the Resource Data Template (RDT) to register their resources under the Generic NGR model. This functionality allows Scheduling Coordinator to submit bids and Base Schedules for resources using Generic NGR model. Additionally, the Generic NGR model will be subject to Local Market Power Mitigation (LMPM) for its entire capacity (Pmax-Pmin). (see BPM for Market Operations Appendices section B.1.2)
- ~~NGRs with resource adequacy capacity do not have a requirement to submit $0/MW availability bids in the RUC.~~ For more information on NGR bidding requirements, see BPM for Reliability Section 7.1.1 Summary of Bidding Requirements for Resources Providing RA Capacity

2.1.13.1 Non-Generator Resources Providing Regulation Energy Management

Under regulation energy management (REM), non-generator resources that require an offset of energy in the real time market to provide regulation can elect to participate only in the ISO's regulation markets. REM functionality will allow an NGR to purchase or sell energy in real-time to meet the continuous energy requirements for regulation procured in the day-ahead market and real time market. When a resource elects REM, the regulation capacity awarded in the day-ahead market is evaluated as four times the regulation energy it can provide within 15 minutes.

Non-Generator Resources providing Regulation Energy Management must register their minimum and maximum energy limits in order for the ISO to continuously optimize and balance the resource through Regulation energy.

Note that the buying and selling of energy in the real-time market supports the regulation obligation. NGRs using Regulation Energy Management do not participate in the ISO's energy market or operating reserves.

2.2 Products & Services

This subsection describes the types of products and services that are traded in the CAISO Markets. The *BPM for Market Instruments* describes these in greater detail.

2.2.1 Energy

2.2.2 Ancillary Services

2.2.3 Residual Unit Commitment Reliability Capacity

The Residual Unit Commitment (RUC) process procures Reliability Capacity to ensure sufficient physical resources are available to meet the CAISO forecast of CAISO demand. This process addresses the potential difference between the physical supply cleared in the Integrated Forward Market (IFM) and the forecasted demand.

Reliability Capacity consists of two distinct products:

- Reliability Capacity Up (RCU) is the incremental capacity procured to meet the positive difference between the CAISO forecast of CAISO demand and the cleared physical supply.

- Reliability Capacity Down (RCD) is the decremental capacity procured to provide downward dispatch capability when the cleared physical supply is greater than the CAISO forecast of CAISO demand.

- ~~Residual Unit Commitment (RUC) Capacity is the positive difference between the RUC Schedule and the greater of the Day-Ahead Schedule and the Minimum Load level of a resource. The RUC Price and the RUC Capacity are determined based on the RUC~~

~~Availability Bids. Virtual Bids are not considered in RUC, but they may influence the RUC outcome based on the amount of unit commitment, Virtual Awards, and physical schedules awarded in the IFM.~~

~~RUC Schedule is the total MW per hour amount of capacity committed by RUC, including the MW per hour amount committed in the Day-Ahead Schedule.~~

2.2.4 Congestion Revenue Rights

2.2.5 Flexible Ramp Product

For information on Flexible Ramp Product refer to Market Operations BPM Appendix Section N.

2.2.6 Imbalance Reserves

Imbalance Reserves are procured to ensure the Day-Ahead Market schedules sufficient dispatch capability to meet net load uncertainty and ramping needs that materialize between the day-ahead and real-time markets. This product is co-optimized with Energy and Ancillary Services in the Integrated Forward Market (IFM).

Imbalance Reserves consist of two distinct products:

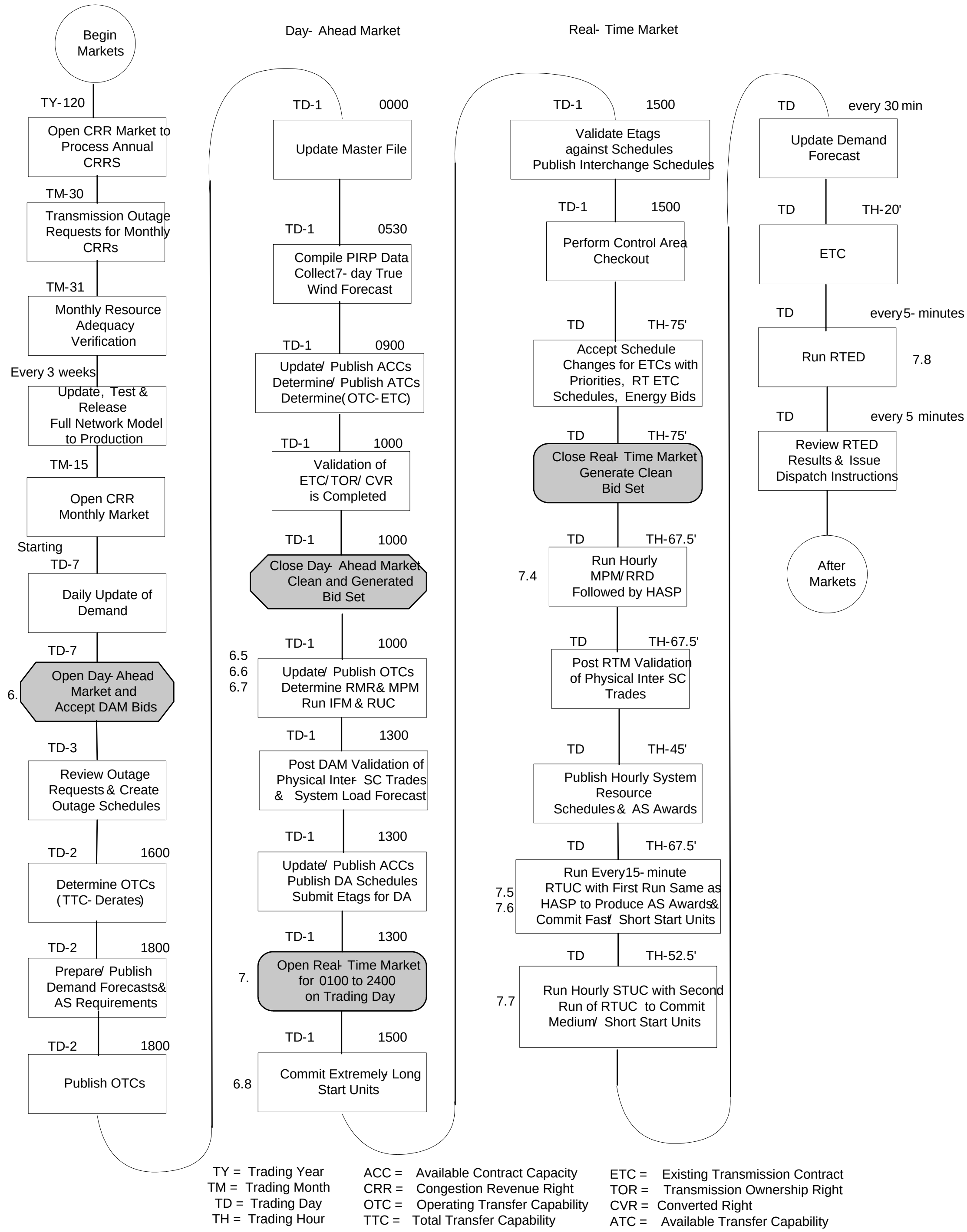
- Imbalance Reserves Up (IRU) is incremental capacity procured to meet upward uncertainty requirements. Resources awarded IRU must be dispatchable in the fifteen-minute market, and the awards are based on the resource's 30-minute ramping capability.

- Imbalance Reserves Down (IRD) is decremental capacity procured to meet downward uncertainty requirements. Resources awarded IRD must be dispatchable in the fifteen-minute market, and the awards are based on the resource's 30-minute ramping capability.

2.3 CAISO Markets

This subsection presents a high level description of the Day-Ahead and Real-Time Markets. Market bidding timelines and primary activities are also discussed. Refer to Exhibit 2-1.[1]

[1] Trading Day-1 refers to the time when the Extra Long Commitment takes place, which happens after the Day Ahead market is complete, from Trading Day-1 1000 to 1300. The 'extremely long unit commitment' process takes place



at 1500, and is still part of the Trading Day-1 process even though it applies to the subsequent day. Please see section 6.8 for further detail.

Exhibit 2-1: CAISO Markets – Overview Timeline

The manual ELC process is in addition to the RUC process and is conducted as part of the Day Ahead Operating Procedures and considers Bids submitted in the DAM for the operations two days out. Any commitment outside this time frame of an ELC resource would be an Exceptional Dispatch.

2.3.1 Day-Ahead Market Processes

Bidding for the Day-Ahead Market (DAM) closes at 1000 hours on the day before the Trading Day and consists of a sequence of processes that determine the hourly Market Clearing Prices for Energy (including physical and Virtual Bids) and AS, as well as the incremental procurement in RUC while also mitigating Bids from to address non-competitive constraints. These processes are co-optimized to produce a Day-Ahead Schedule at least cost while meeting local reliability needs. The CAISO ensures that Virtual Bids (Supply and Demand) are not passed from the IFM to RUC or RTM.

TTC pertains to all interties, and to significant corridors such as Path 15 and Path 26. The TTC is updated for the DAM and RTM as needed. The details of TTC calculation and timeline are provided in Section **Error! Reference source not found.**~~5.2~~. TTC reduction cutoff 0900 hours. However uprates are allowed up to 1000 hours

The prices resulting from these processes are used for the Day-Ahead Market Settlement. The timeline for the Integrated Forward Market is shown in Exhibit 6-1. The following subsections present an overview of these processes for the Trading Day. Further details are presented in Section 6, Day-Ahead Market Processes.

2.3.1.1 Day-Ahead Market Power Mitigation (MPM)

2.3.1.2 Integrated Forward Market

The IFM is a market for trading physical and virtual Energy, ~~and~~ Ancillary Services, and Imbalance Reserves for each Trading Hour of the next Trading Day. IFM uses Clean Bids from SIBR[2] (i.e., that pass the SIBR validation rules) and the mitigated Energy and Imbalance Reserve Bids to the extent necessary after MPM in order to clear physical and Virtual Supply and physical and Virtual Demand Bids and to procure AS and Imbalance Reserves to meet one-hundred percent of CAISO's AS requirements and the Imbalance Reserve requirement at least cost over the Trading Day. Refer to Section 6.6, Integrated Forward Market, for further details.

[2] This process is described in more detail in the *BPM for Market Instruments*, Section 8.

2.3.1.3 Residual Unit Commitment

Residual Unit Commitment is a reliability function for committing resources and procuring ~~RUC~~ Reliability Capacity not scheduled in the IFM. ~~(as physical Energy or AS capacity.) RUC Capacity~~Reliability Capacity Up (RCU) is procured ~~in order~~ to meet the difference between the CAISO Forecast of CAISO Demand (CFCD) (including locational differences and adjustments) and the ~~Demand~~ physical supply scheduled in the IFM~~,~~ for each Trading Hour of the Trading Day. Conversely, Reliability Capacity Down (RCD) is procured to provide downward dispatch capability when the physical supply scheduled in the IFM exceeds the CFCD.

~~-~~The CAISO runs the RUC process for the 24-hour Trading Day to ensure sufficient physical capacity is available and committed at least cost to meet the CAISO Forecast of CAISO Demand, subject to transmission and resource operating constraints. RUC achieves this objective by minimizing the total of Start-Up Costs, Minimum Load Costs, and incremental availability costs from RCU and RCD Bids.

Due to locational constraints, it is possible that RUC may procure Reliability Capacity and commit resources even when the total physical supply scheduled in the IFM is sufficient to meet the system-wide CFCD. This can happen because the locational quantity of load scheduled in the IFM may be different than the locational quantity of load after distributing the adjusted CAISO Forecast of CAISO Demand in RUC. In addition, RUC may need to commit resources to the extent virtual supply has displaced physical supply in the IFM.

~~In addition, RUC anticipates supply and demand over a longer look-ahead time period (default to 72 hours but can be up to 168 hours, compared to 24 hours in the IFM). This allows RUC issue advisory commitment instructions for Extremely Long-Start Resources which may not be considered in the IFM due to their long start-up times. These advisory instructions are considered as part of the ELS commitment process described in Section 6.8 below. In order to reduce cycling of resources through the transition from one day to another, RUC looks-ahead beyond the binding 24 hour period as it procures capacity and make commitment decisions for the applicable binding time horizon, taking into account expected needs in the forward days beyond the 24 hour time period. Refer to Section 6.7, Residual Unit Commitment. The CAISO, however, runs the RUC process for every Trading Day regardless of the difference between the CFCD and the Scheduled Demand in the IFM. The objective of the RUC is to ensure sufficient physical capacity is available and committed at least cost to meet the adjusted CAISO Forecast of CAISO Demand for each hour of the next Trading Day, subject to transmission and resource operating constraints. RUC achieves this objective by minimizing the total of Start-Up Costs, Minimum Load Costs and incremental availability costs (i.e., RUC Availability Bids). As a result, it is possible that when RUC runs RUC may procure Capacity and possibly commit resources even though the CAISO Forecast of CAISO Demand prior to the taking into account the~~

~~locational differences and adjustments, is equal or less than the Scheduled Demand of the SCs resulting from the IFM. This can happen because the locational quantity of load scheduled in the IFM may be different than the locational quantity of load after distributing the adjusted CAISO Forecast of CASIO Demand in RUC. In addition, RUC may need to commit resources to the extent virtual supply displaces physical supply in the IFM.~~

Resources receive a binding Start-Up Instruction from RUC (if committed by RUC)~~,~~ only if they must receive a ~~start up~~start-up instruction in the DAM to meet requirements in RTM. Other resource commitment decisions are determined optimally in the RTM. For details on the commitment of Extremely Long-Start resources, refer to Section 6.8.

2.3.1.4 Extremely Long-Start Commitment

2.3.2 Real-Time Processes

2.4 Roles & Responsibilities

This subsection identifies and describes the basic roles and responsibilities of the entities that participate in the CAISO Markets.

2.4.1 Utility Distribution Companies

2.4.2 Metered Subsystems

2.4.2.1 MSS System Unit

2.4.2.2 MSS Elections & Participation in CAISO Markets

This section is based on CAISO Tariff Section 4.9.13.

MSS entities must make an annual election on the manner in which the MSS intends to participate in the CAISO Markets. All MSS entities will participate in the RUC procurement process. The MSS entity must make annual choices for each of the following:

- Choose either net settlements or gross settlements. This election must be made 60 days in advance of the annual CRR allocation process in accordance with CAISO Tariff Section 4.9.13.1.
- Choose to Load-follow or not Load-follow with its Generating Units. This annual election must be made 6 months in advance of the implementation of Load-following capability. MSS entities who choose to Load-follow:

- Prior to making an election contact Client Services and Stakeholder Affairs for information on Load-following at: ISOClientRepresentatives@caiso.com
- The transition must occur on the first of the month. See BPM for Reliability Requirements section 3.4 “Load-Following Metered Subsystem” for specific resource adequacy provision.

- ~~Choose to have its Load participate in the Residual Unit Commitment procurement process and therefore CAISO procures RUC Capacity to meet the MSS Operators' needs, or not have its Load participate in the RUC procurement process, in which case CAISO will not procure RUC Capacity for the MSS. MSSs that elect to Load-follow must not participate in the RUC procurement process. This election must be made 60 days in advance of the annual CRR allocation process in accordance with CAISO Tariff Section 31.5.2.~~

- Choose to charge the CAISO for Emission Costs. This annual election must be made on November 1 for the following calendar year in accordance with CAISO Tariff Section 11.7.4.

Annual elections must be sent to Regulatory Contracts pursuant to the MSS Agreement. These elections may be scanned into a Portable Document Format (PDF) and e-mailed to RegulatoryContracts@caiso.com with a hard copy original to follow.
Mail to:

California Independent System Operator Corporation

Regulatory Contracts

250 Outcropping Way

Folsom, CA 95630

2.4.2.3 Permitted MSS Election Options

The table below lists the permitted combinations of MSS election options.

Load Following	RUC Participation	CRR Allocation and Settlement Election
~~No~~	~~No~~	~~Gross~~
~~No~~	~~No~~	~~Net~~
No	Yes	Gross
No	Yes	Net
Yes	~~N/A~~Yes	Net
Yes	~~N/A~~Yes	Gross

2.4.3 Participating Transmission Owners Information

2.4.4 Participating Generators & Participating Loads

2.4.5 Scheduling Coordinator Responsibilities

This section is based on CAISO Tariff Section 4.5.2.2, SC Representing Convergence Bidding Entities, Section 4.5.3, Responsibilities of a Scheduling Coordinator and Section 4.5.4, Operations of a Scheduling Coordinator

Each Scheduling Coordinator (SC) is responsible for the following. Additional information is presented in the *BPM for Scheduling Coordinator Application & Responsibilities*:

- Obligation to pay CAISO's charges in accordance with the CAISO Tariff
- Depending on the Markets in which the SC wants to participate, submit Bids in the Day-Ahead Market and the Real-Time Market in relation to Market Participants for which it serves as an SC. This includes submitting bids for Imbalance Reserves and Reliability Capacity.~~;~~ SCs provide CAISO with intertie schedules prepared in accordance with all NERC, WECC, and CAISO requirements, including providing E-Tags for all transactions
- Coordinating and allocating modifications in Demand and exports and Generation and imports at the direction of CAISO in accordance with the CAISO Tariff Section 4.5.3.
- Submitting any applicable Inter-SC Trades that the Market Participants intend to have settled through the CAISO Markets, pursuant to the CAISO Tariff
- Tracking and settling all intermediate trades, including bilateral transactions and Inter-SC Trades, among the entities for which it serves as SC
- Providing Ancillary Services in accordance with the CAISO Tariff
- Submitting to CAISO the forecasted weekly peak Demand on the CAISO Controlled Grid and the forecasted Generation capacity. The forecasts cover a period of 12 months on a rolling basis
- Complying with all CAISO Business Practice Manuals and ensuring compliance by each of the Market Participants which it represents with all applicable provisions of the Business Practice Manuals

- Identifying any Interruptible Imports included in its Bids or Inter-SC Trades
- Submitting Schedules for Participating Intermittent Resources consistent with the CAISO Tariff
- Submitting Bids so that any service provided in accordance with such Bids does not violate environmental constraints, operating permits or applicable law. All submitted Bids must reflect resource limitations and other constraints as such are required to be reported to the CAISO Control Center
- Other than a Scheduling Coordinator that engages solely in financial activity (i.e. Virtual Bidding on behalf of Convergence Bidding Entities and Inter-SC Trades), each SC operates and maintains a 24-hour, seven days per week, scheduling center. Each SC designate a senior member of staff as its scheduling center manager who is responsible for operational communications with CAISO and who has sufficient authority to commit and bind the SC
- Scheduling Coordinator is responsible for providing GDF's for Aggregate Generating Resources. Default GDFs will be used in absence of this data. These default GDF's are derived from the State Estimator and they are maintained in the GDF Library.
- The Scheduling Coordinator is responsible for registering and bidding resources as Multi-Stage Generating Resources pursuant to Section 27.8 of the CAISO Tariff. Information on registration of Multi-Stage Generating Resources is available at: http://www.caiso.com/27bd/27bdc1ce2f430.html
- SCs submit Bids for imports of Energy and Ancillary Services for which associated Energy is delivered from Dynamic System Resources located outside of the CAISO Balancing Authority Area, provided that:
  - Such dynamic scheduling is technically feasible and consistent with all applicable NERC and WECC criteria and policies
  - All operating, technical, and business requirements for dynamic scheduling functionality, as posted in standards on the CAISO Website[3], are satisfied
  - The SC for the dynamically scheduled System Resource executes an agreement with CAISO for the operation of dynamic scheduling functionality

[3] The relevant information can be found at: http://www.caiso.com/docs/09003a6080/2f/c8/09003a60802fc882ex.html

- All affected host and intermediary Balancing Authority Areas each execute with CAISO an Interconnected Balancing Authority Area Operating Agreement or special operating agreement related to the operation of dynamic scheduling functionality

- SCs need to register Proxy Demand Resources (PDR) resources with CAISO.

- SCs must submit GDFs with the bids for PDRs with dynamic GDFs. For PDRs with static GDFs, SCs are expected to provide GDFs during registration.

➢ SCs need to register with the CAISO to submit Virtual Bids on behalf of registered Convergence Bidding Entities.

- SCs need to identify which Convergence Bidding Entities (CBEs) it will represent (including itself, if applicable). SC/CBE relationships will be modeled in the Master File for the basis of Position Limits.

- The parent SC (i.e. corporate or governmental entity contracting with the CAISO to participate in the CAISO Markets) must ensure collateral is provided sufficient to cover simultaneous CRR and Virtual Bid credit exposure as well as all other market activity.

➢ SCs need to submit information regarding affiliates that participate in the CAISO Markets and information concerning any Resource Control Agreements on forms and at times specified in the Business Practice Manual for Scheduling Coordinator Certification & Termination and Convergence Bidding Entity Registration & Termination. This information is needed for proper operation of the dynamic competitive path assessment.

➢ For Distributed Curtailed Resources (DCR), SCs must obtain approval to use any Performance Evaluation Methodology (PEM) and, to calculate the Demand curtailment provided by the DCR within a Distributed Energy Resource Aggregation (DERA), the SC must calculate its Demand Response Energy measurement (DREM). For more information regarding DERA resources, refer to the Demand Response BPM.

2.5 Market Information

This section summarizes and describes the common information that is used by the Day-Ahead and Real-Time processes.

2.5.1 Resource Static Data

2.5.2 Bids

Bids are submitted by SCs for each of the CAISO Markets. These Bid components are summarized as follows and are described further in the *BPM for Market Instruments,* Section 5:

- Start-Up Time and Start-Up Cost
- Minimum Load Cost
- Transition Costs
- ~~RUC Availability Bid~~
- Regulation Up and Regulation Down Capacity Bids
- Regulation Up and Regulation Down Mileage Bids
- Spinning Reserve and Non-Spinning Reserve Bids
- Imbalance Reserves Up and Imbalance Reserves Down Bids
- Reliability Capacity Up and Reliability Capacity Down Bids
- Import Bid and Export Bid
- Energy Bid Curve and daily Energy Limits
- Generation Distribution Factors
- Ramp Rates
- Virtual Supply and Virtual Demand Bids in Day-Ahead Market.

SIBR processes Bids through a series of validation rules and, in the case of Virtual Bids, submits such bids to a credit check prior to Market Close. A warning is issued from SIBR if the Bid is not valid and the Scheduling Coordinator is given an opportunity to cancel the Bid and resubmit the bid, time permitting. After Market Close, SIBR creates Clean Bids, or generates Bids (described in more detail in the *BPM for Market Instruments,* Section 8) in accordance with CAISO Market rules. Clean Bids and Generated Bids are pushed to the DAM market processes. Additional detail regarding the Bid validation process is in the BPM for Market Instruments.

2.5.2.1 Self-Schedules

2.5.2.2 Wheeling

The CAISO Tariff defines Wheeling as “Wheeling Out or Wheeling Through”

Wheeling Out is defined to mean: “Except for Existing Rights exercised under an Existing Contract in accordance with Section 16.1, the use of the CAISO Controlled Grid for the transmission of Energy from a Generating Unit located within the CAISO Controlled Grid to serve a Load located outside the transmission and Distribution System of a Participating TO."

Wheeling Through is defined to mean: "Except for Existing Rights exercised under an Existing Contract in accordance with Section 16.1, the use of the CAISO Controlled Grid for the transmission of Energy from a resource located outside the CAISO Controlled Grid to serve a Load located outside the transmission and Distribution System of a Participating TO."

These tariff definitions specify transactions for which the ISO collects Wheeling Access Charges.

In the CAISO's Market, a Wheeling Out transaction consists of an Export Bid or Demand Bid for a transaction that leaves the ISO Controlled Grid (both inside and outside the Balancing Authority). The Export Bid or Demand Bid may be in the form of a Self-Schedule and/or an Economic Bid.

In the CAISO's market, a Wheeling Through transaction consists of an Import Bid and an Export Bid with the same Wheeling reference. The Export/Import Bids may be in the form of a Self-Schedule and/or an Economic Bid. A Wheeling Through transaction is identified with a unique wheeling reference ID which is registered in the CAISO Master File. The Wheeling Through transaction can be specified between any two Scheduling Points in the system. The schedules of the import and export resources in a Wheeling Through transaction are kept balanced in the SCUC co-optimization engine. Any Self-Schedules can be uneconomically adjusted respecting assigned priorities as described in CAISO Tariff Sections 31.4 and 34.10. An E-Tag or E-Tags for a Wheeling Through transaction must reflect a resource outside of the CAISO Controlled Grid as the source of the transaction. An E-Tag or E-Tags for a Wheeling Through transaction that leaves the ISO Balancing Authority Area must reflect a sink outside of the CAISO Controlled Grid.

Wheeling Through is associated with the entire Energy Bid, i.e., both the Self-Schedule quantity and the Economic Bid price curve. The balancing of wheeling energy is enforced by the constraint:

Total export MW schedule = Total import MW schedule

This constraint is enforced for each wheeling pair and each time interval in the MPM, IFM, and RTM.

Wheeling Through transactions will be ignored in RUC, since the Day-Ahead Schedule for Energy (i.e., the IFM Energy Schedules), which includes the Wheeling Through transactions are fixed at the IFM Energy Schedule quantities. These IFM Energy Schedules receive a higher priority with respect to ~~RUC Availability~~Reliability Capacity Bids in meeting CFCD. Therefore, energy flows due to wheeling transactions that clear the IFM are included in the RUC optimal solution. RUC may back down IFM Energy Schedules to Minimum Load to achieve a solution. However, these adjustments are not subject to Settlements implications. Because there is no actual Energy delivered with a Wheel Through, the import side of a Wheel Through is not eligible for Energy Bid Cost Recovery.

2.5.3 Inter-SC Trades

2.5.4 Existing Transmission Contracts, Transmission Owner Rights, & Converted Rights

2.5.5 Scheduling Priorities for Exports, Load, and Wheels

2.5.5.1 PT export scheduling priority

In the day-ahead market, the scheduling priority of exports relative to load depends on whether the exporting scheduling coordinator designates an internal-to-CAISO resource with non-RA capacity as supporting the export. If a scheduling coordinator identifies an export self-schedule as supported by non-RA capacity, that export receives equal scheduling priority as CAISO self-scheduled load in IFM and the CAISO load forecast in RUC. These exports are referred to as Price Taker (PT) exports. Any export self-schedules that do not identify non-RA capacity supporting the export will still be price takers, but they will have lower scheduling priority than CAISO self-scheduled load in IFM and demand forecast in RUC. These exports are referred to as Lower Price Taker (LPT) exports. This means that if there is insufficient supply or binding transmission constraints, these LPT exports will only clear if there is sufficient supply to first serve self-scheduled CAISO load or demand forecast, and PT exports. This ensures CAISO resource adequacy capacity cannot be used to support exports when it is needed to serve CAISO load. Finally, if there is sufficient supply to clear all self-scheduled day-ahead export and load self-schedules, economic load and export bids will be considered.

In the real-time market, the scheduling coordinator for a PT export that receives a day-ahead schedule must re-declare a supporting resource to support the high-priority export. If a supporting resource is not designated in the real-time market bid, the export will be assigned lower real-time market priority than PT exports but higher priority than the LPT exports submitted in the real-time market.

2.5.5.2 LPT and Economic Export Priorities

Lower priority exports (i.e., exports not backed by non-RA supply) that receive a day-ahead market schedule will have a lower priority than CAISO load, and will be appropriately curtailed in the day-ahead market to minimize the export of RA capacity dedicated to CAISO load during tight system conditions. LPT and economic exports must secure capacity from a non-RA resource in order to receive high priority in the real-time market.

LPT exports and economic exports that are deemed feasible in RUC and are self-scheduled into the real-time market will receive higher priority than LPT exports and economic exports bidding in the real-time market.

2.5.5.2.1 Identify Resource that can support Export

A Master File flag, through the Resource Data Template (RDT) submitted by scheduling coordinator, will define a generating resource or a non-generator resource to indicate whether the resource can be designated to support a high priority export. To qualify as a designated resource for an export self-schedule, the resource must meet the following qualifications:

- The designated resource must be a generating resource or a non-generator resource that is only internal to the CAISO BAA.

- The Scheduling Coordinator of the designated resource must attest that the resource is capable of supporting a PT export from its non-RA capacity bid in the market and has been forward contracted with an external load serving entity.

- The ISO will notify a scheduling coordinator hourly that its resource is supporting a PT Export.

- The designated capacity must be the deliverable capacity of a resource with Full Capacity Deliverability Status, Partial Capacity Deliverability Status, or Interim Deliverability Status that is shown on the CAISO's NQC list, because these resources have not completed a deliverability assessment in the generator interconnection process and thus cannot ensure deliverability. Because such resources cannot sustain an hourly block schedule if there is local congestion, these type of resources cannot be designated to support a high priority export.

- ~~The supporting resource will be assigned a $0/MW RUC availability bid equal to the PT export self-scheduled quantity.~~The supporting resource is required to submit a Reliability Capacity Up (RCU) bid for the quantity supporting the PT export self-schedule. If the Scheduling Coordinator for the supporting resource fails to submit an RCU bid, a Default Availability Bid (DAB) will be inserted by the system.

- If the supporting resource for a PT export does not receive ~~a RUC schedule~~an RCU award, the scheduling coordinator must rebid the resource in the real-time market for the export to maintain PT priority. If the export does not rebid in real-time with a designated resource, the export's real-time scheduling priority will be equivalent to a day-ahead LPT export (i.e., lower priority than CAISO load but higher priority than LPT exports) up to its ~~RUC award.~~cleared RCU quantity from the RUC process.

2.5.5.2.2 PT status in RTM

PT status in real-time market can be provided through two means;

1. If the same designated resource is specified in the real-time market bid as it was specified in the day-ahead market bid: The lower of the designated resource's RUC schedule or day-ahead export RUC schedule will receive the PT scheduling priority.

2. If a different designated resource is specified in the real-time market bid from the one that was specified in the day-ahead market bid: The portion of the export self-schedule supported by the designated resource bid into the real-time market with available non-RA capacity above the resource's RUC schedule will receive the PT scheduling priority.

The same scheduling priority in real-time applies in both situations.

Example:

Export A1 is a 100MW export self-schedule with Generator A as a designated supporting resource. Generator A bids 80MW in the day-ahead market. Therefore, the export A1 receives the PT scheduling priority for 80 MW and the LPT scheduling priority for the remaining 40MW. Generator A receives an 80MW schedule in IFM but is curtailed to 60MW in RUC. That means Export A1 can only receive 60MW of day-ahead PT priority; however, the scheduling coordinator may bid another export A2 specifying Generator A as a Supporting Resource. Generator A bids 30MW in real time above its RUC schedule supporting A1 for up to 30MW for the PT scheduling priority. The remaining 30MW of A2 receive the real-time LPT priority. The other examples follow a similar logic.

Resource	DAM Bid	Supporting Resource	DAM Priority	RUC Schedule	RTM Bid	Supporting Resource	RTM Priority
Export A1	100 PT 20 LPT	Generator A	80 DAPT 40 DALPT	120	60 PT	Generator A	60 DAPT
Export A2					30 PT 30 LPT	Generator A	30 RTPT 30 RTLPT
Generator A	80			60	90		
Export B1	100 PT 20 LPT	Generator B	80 DAPT 40 DALPT	100	60 PT 50 LPT	Generator B	60 DAPT 40 DALPT 10 RTLPT
Export B2					10 PT 10 LPT	Generator B	10 RTPT 10 RTLPT
Generator B	80			60	70		
Export C	100 PT 20 LPT	Generator C	80 DAPT 40 DALPT	100			100 DALPT
Generator C	80			60	70		
Export D	100 PT 20 LPT	Generator D	80 DAPT 40 DALPT	100			80 DAPT 20 DALPT
Generator D	80			80	80		

DAPT = RTPT = Load/Demand > DALPT > RTLPT

2.5.5.2.3 Scheduling Priorities for Wheeling Through the CAISO Transmission System

- **Priority and Non-Priority Self-Scheduled Wheeling Throughs**

- Section 23 of the ISO Tariff establishes the terms and conditions and the overall process of establishing Wheeling Through Priority across the CAISO system.
- The penalty price for the import leg of a non-Priority Wheeling Through transaction is set to $0/MWh, and the penalty price for the export leg of a non-Priority Wheeling Through is set at the same level as LPT exports.
- The penalty price for the import leg of a Priority Wheeling Through transaction is set at the same level as self-scheduled imports serving CAISO load, and the penalty price of the export leg of a Wheeling Through Priority transaction is set at the same level as PT exports.
- The Scheduling Coordinator needs to register an export system resource in the Master File prior to scheduling of the wheel through, so that the wheel can be treated as a Wheeling Through Priority in the market. See below for further details.

2.5.5.2.3(a) Wheeling Through Priority Process

2.5.5.2.3(b) Establishing monthly and daily Wheeling Through Priority

2.5.5.2.3(b)(1) Monthly Requests for ATC

2.5.5.2.3(b)(2) Daily Requests for ATC

2.5.5.2.3(b)(3) Termination or Modification

2.5.5.2.3(b)(4) Posting of ATC Information on OASIS

2.5.5.2.3(b)(5) Resales of ATC for Wheeling Through Priority

2.5.5.2.3(b)(6) Registration of Resource in Masterfile to Support Wheeling Through Priority

2.5.5.2.3(b)(7) Using ETC or TOR Capacity to Support Wheeling Through Priority

A Scheduling Coordinator may use ETC or TOR capacity on the CAISO system to support Wheeling Through Priority. The scheduling coordinator may schedule its ETC or TOR consistent with their rights.

A Scheduling Coordinator may use ETC or TOR capacity for that portion of the Wheeling Through Priority from the import Scheduling Point to the export Scheduling Point that is covered by the ETC or TOR capacity the Scheduling Coordinator chooses to use. In order to establish the Wheeling Through Priority that is associated with one leg of transmission exercising ETC/TOR, the scheduling coordinator can submit a request for ATC for the second leg of transmission.

In submitting such a request for ATC, the Scheduling Coordinator must state its intent to support the request for Wheeling Through Priority ATC via its ETC/TOR, identify the specific contract reference number (CRN) associated with these rights, identifying the ultimate source on the CAISO system (import point based on the use of its ETC/TOR) and sink, and meet all the relevant requirements for submission of an ATC request, including meeting the attestation requirement. If such a request for Wheeling Through Priority is awarded to a Scheduling Coordinator, the scheduling must schedule the Wheeling through Priority concurrently with the exercise of ETC/TORs and may not schedule the Wheeling Through Priority separately.

- **Tagging of Wheeling Through Priority transactions**

Consistent with section 2.5.2.2 of this BPM, an E-Tag or E-Tags for a Wheeling Through transaction must reflect a resource outside of the CAISO Controlled Grid as the source of the transaction. An E-Tag or E-Tags for a Wheeling Through transaction that leaves the CAISO Balancing Authority Area must reflect a sink outside of the CAISO Controlled Grid.

Wheeling Through Priority transactions should be tagged with a 7-F transmission profile across the ISO transmission system representing the high level firmness of the transaction, as has been practice of parties to date.

- **Administrative process before the HASP schedules are published.**

  In the post-HASP process, when HASP uneconomic adjustment takes place (either under-generation relaxation of the power balance constraint and/or PT Wheel self-schedule cuts) and intertie scheduling limits are binding in the import direction, all low priority wheel through transactions will be curtailed to 0 MW prior to allocating available transmission capacity between Wheeling Through Priority transactions and CAISO load.

The CAISO will apply a pro rata allocation for transmission capacity on an intertie that is constrained in the import direction by a scheduling limit between import -schedules, and high priority wheeling self-schedules, as follows:

D *= min (PT Wheel SS, Import Limit) + min (RA Import Bid/SS, Import Limit)*

Adjusted Import Schedule *= min (RA Import Bid/SS, Import Limit) * Import Limit / D*

Adjusted PT Wheel Schedule *= min (PT Wheel SS, Import Limit) * Import Limit / D*

The individual schedules in each of the two allocated totals are determined in merit order. The Import Limit is reduced by any TOR/ETC self-schedules that have higher scheduling priority and are not subject to this pro rata allocation.

The CAISO also applies a similar pro rata allocation method for allocating southbound transmission capacity on Path 26, between supply schedules, north of Path 26 and high priority southbound wheeling self-schedules through Path 26 when Path 26 is constrained in the north-south direction, and when the HASP optimal solution shows uneconomic adjustments among said schedules and/or load.

The pro-rata allocation formula is as follows;

D *= min (PT Wheel SS, Path26 N-S Limit) + min (RA Bid/SS – PG&E TAC Demand Forecast, Path26 N-S Limit)*

Adjusted Gen/Import Schedule *= min (RA Bid/SS – PG&E TAC Demand Forecast, Path26 N-S Limit) * Path26 N-S Limit / D*

Adjusted PT Wheel Schedule *= min (PT Wheel SS, Path26 N-S Limit) * Path26 N-S Limit / D*

The individual internal supply schedules are kept at their optimal HASP schedules, whereas the individual import and PT wheeling schedules in each of the two allocated totals are determined in merit order. The Path 26 N-S Limit is reduced by any TOR/ETC self-schedules on Path 26 North-South that have higher scheduling priority and are not subject to this pro rata allocation.

Examples:

Example1: Pro rata allocation of import capability between RA Imports and PT Wheel schedules at the intertie scheduling point.

Import limit: 300MW

RA Import bid: 200MW

PT Wheel: 200MW

HASP Solution is uneconomic (under-generation by more than 100MW): Import: 100MW, PT Wheel: 200 MW

Pro rata allocation of 300MW import capacity between the RA Import and PT Wheel:

Adjusted Import Schedule = 200*[300/(200+200)] = 150MW

Adjusted PT Wheel Schedule = 200*[300/(200+200)] = 150MW

Example 2: It builds upon the previous example, but introduces non-RA import RUC schedules. The result of the pro rata allocation between total Import and PT Wheel schedules is the same.

Import limit: 300MW

Non-RA Import (RUC Schedule): 100MW

RA Import Bid: 200MW

PT Wheel: 200MW

HASP Solution is uneconomic (under-generation by more than 100MW): Non-RA Import: 100MW, RA Import: 0MW, PT Wheel: 200 MW

Pro rata allocation of 300MW import capacity between the Imports and PT Wheel:

Adjusted Import Schedule = 200*[300/(200+200)] = 150MW

Adjusted Non-RA Import Schedule: 100MW

Adjusted RA Import Schedule: 50MW

Adjusted PT Wheel Schedule = 200*[300/(200+200)] = 150MW

Example 3: It builds upon the previous examples, but the Import and PT Wheel pro rata shares are limited by the import limit.

Import limit: 300MW

Non-RA Import (RUC Schedule): 100MW

RA Import Bid: 400MW

PT Wheel: 400MW

HASP Solution is uneconomic (under-generation by more than 100MW): Non-RA Import: 60MW, RA Import: 0MW, PT Wheel: 240 MW

Pro rata allocation of 300MW import capacity between the Imports and PT Wheel:

Adjusted Import Schedule = min(400,300)*[300/((min(400,300)+min(400,300))] = 150MW

Adjusted Non-RA Import Schedule: 100MW

Adjusted RA Import Schedule: 50MW

Adjusted PT Wheel Schedule = min(400,300)*[300/((min(400,300)+min(400,300))] = 150MW

3. Full Network Model

Welcome to the *Full Network Model* section of the CAISO *BPM for Market Operations*. In this section, you will find the following information:

- A description of the models and terminology that are used to coordinate the Full Network Model (FNM) with the CAISO Markets
- The FNM is discussed from the market operations perspective

The *BPM for Managing Full Network Model* provides further details, including the relationship between the reliability model and the network model, the base case, the AC solution, and the CRRs. Remedial Action Schemes (RAS)[4] are also described in the BPM.

3.1 Model Description

3.1.1 Real-Time Data

3.1.2 Generation Distribution Factors

3.1.3 Modeling Point

3.1.4 Load Distribution Factors

SCs must submit Bids for Non-Participating Load resources at an aggregate location (ANode). The IFM optimally schedules Non-Participating Load based on its aggregate Bid at the corresponding ANode. The aggregate Load schedule is decomposed using the relevant LDFs to individual physical Load schedules for power flow calculations in the Full Network Model. MPM, RUC and RTM also use LDFs to decompose the CAISO Forecast of CAISO Demand (CFCD)

[4] RAS are implemented to maintain system reliability and are not managed as part of the market optimization. To the extent that RAS operations affect transmission constraints, the corresponding limits are enforced by the market applications.

for power flow calculations in the Full Network Model. These LDFs always sum up to 1.0 for a given aggregation.

If there is a Virtual Supply Bid or Virtual Demand Bid at the Default LAP location, the Default LAP LDF will be applied to the Virtual Bid in the same way as the physical Demand Bid, thereby treating physical and Virtual Bids consistently in the Day-Ahead Market. Default LAP LDF's will not be affected by Virtual Supply Bids or Virtual Demand Bids at an individual node. Default LAP LDF's are based on physical load.

CAISO maintains a library of LDFs for use in distributing Load Aggregate schedules at Default or Custom LAPs in IFM and the CFCD in MPM and RUC. These LDFs are derived from the EMS State Estimator (SE) and are stored in the LDF Library. The LDF Library gets feeds from the SE, and keeps a historical average of LDFs for different system conditions. For RTM, the SE solution is used directly as the source of LDFs. For DAM, the appropriate LDFs are used from the LDF Library. The LDF Library produces historical average LDFs based on a similar-day methodology that uses data separately for each day of the week and holidays, rather than for weather conditions. More recent days are weighted more heavily in the smoothing calculations. The ISO may adjust load distribution factors prior to use by the market application to reflect weather conditions expected in the market time horizon.

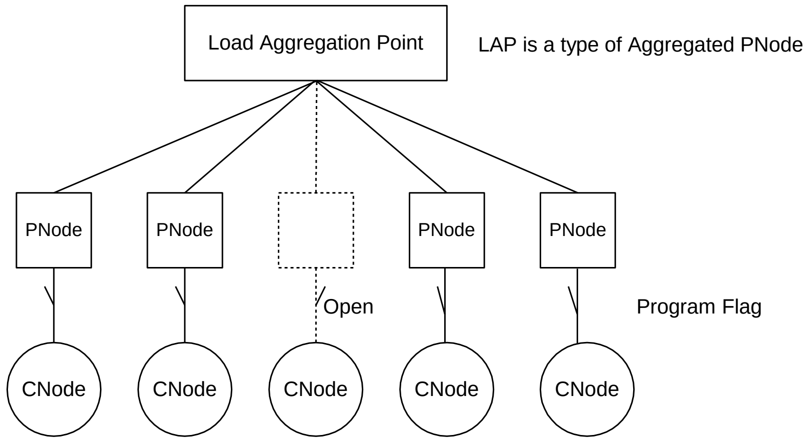
CAISO also maintains a set of Load Aggregation Factors (LAFs) in the Master File for each Default or Custom LAP. These LAFs represent the percentage sharing of load at the CNode among different overlapping LAPs.

The CAISO Market applications then use the set of LDFs from the library that best represents the Load distribution conditions expected for the market Time Horizon. If LDFs are not available in the LDF Library, static LDFs can be loaded into the system.

The Energy Settlement for Non-Participating Load resources is at the corresponding Aggregate LMP. That Aggregate LMP is calculated after Market Clearing as the weighted average of the LMPs at the individual load locations (CNodes). The weights in the Aggregate LMP calculation are the relevant LDFs.

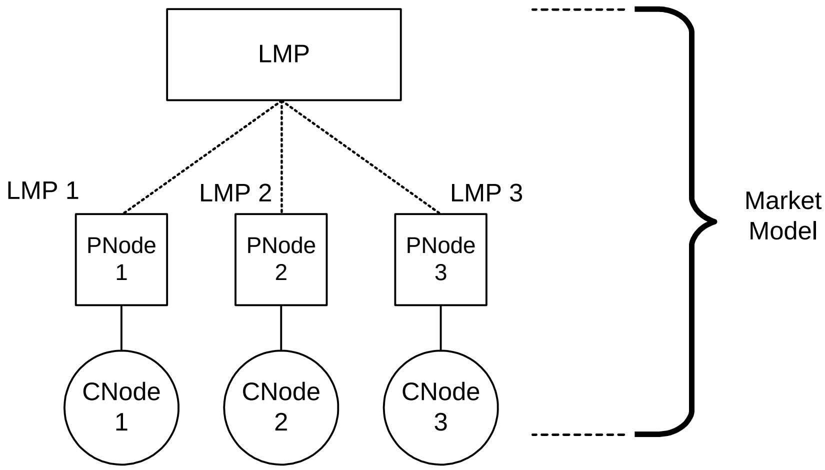
Exhibit 3-4 illustrates the model of a LAP.

Exhibit 3-14: Load Aggregation Point



CNode = Connectivity Node
PNode = Pricing Node

Exhibit 3-2~~5~~: Modeling Point



3.1.5 Aggregated Pricing Nodes

3.1.6 Losses

3.1.7 Nomograms

3.1.8 Transmission Element & Transmission Interfaces

3.1.9 Scheduling Points

3.1.10 Unscheduled Flow Estimation

3.1.11 Nodal Group Limit Constraints

3.1.12 Controllable Devices Modeling

3.1.13 Generator Contingency and Remedial Action Scheme modeling

3.1.14 Aggregated Capability Constraint for Co-Located Resources

The CAISO will allow Co-located Resources that elect to use the Aggregate Capability Constraint to register their maximum operating limit as their Pmax, even if the aggregate values of these maximum operating limits are greater than the interconnection service capacity set forth in their Generating Facility's interconnection agreement. Using the Aggregate Capacity Constraint (ACC) functionality, the CAISO will limit market awards and dispatches from co-located resources to the total amount of the Generating Facility's interconnection service capacity.

Formulation

The full constraint follows:

$$MAX[0,\Sigma(ENi+RUi+SRi+NRi+IRUi+RCUi+FRUi)i\in S]\leq UL$$
$$MIN[0,\Sigma(ENi+RDi+IRDi+RCDi+FRDi)i\in S]\geq LL$$

Where:

i Resource

S Set of resources

EN Energy schedule

UL Upper limit

LL Lower limit

RU Regulation up award*

RD Regulation down award*

SR Spinning reserve award*

NR Non-spinning reserve award*

IRU Imbalance Reserve Up award*

IRD Imbalance Reserve Down award*

RCU Reliability Capacity Up award*

RCD Reliability Capacity Down award*

FRU Flexible ramp up award

FRD Flexible ramp down award

Note: Co-located Resources that do not follow dispatch instructions will lose eligibility to use the aggregate capability constraint. Such co-located resources will revert back to the current methodology where;

ΣPMax <= ACC max limit and ΣPMin >= ACC min limit.

3.1.14.1 Enforcement of Aggregate Capability Constraints

Tariff Section 27.13 describes the consequences when co-located resources utilizing an aggregate capability constraint (ACC) exceed the Interconnection Service Capacity limits for their Generating Facility.

Upon identification of a potential exceedance situation, the CAISO will notify the Interconnection Customer, and the Scheduling Coordinator(s) associated with the resources included in the ACC. Upon notification, the Interconnection Customer will have seven (7) calendar days to provide a response to the CAISO via their Scheduling Coordinator(s) explaining the exceedance and any steps being taken to address the issue.

Upon resolving the issue, the Interconnection Customer, via their Scheduling Coordinator(s), shall provide the CAISO with a final written report identifying the cause of the issue and its resolution via reply to the notification email.

If the CAISO has not received written confirmation from the associated Scheduling Coordinator(s) that the issue is resolved within fourteen (14) calendar days from the date of the CAISO's notice, the CAISO will implement a pro-rata cut to the Pmax values in the Master File for the resources within the ACC to match the ACC limit unless the Interconnection Customer has requested a different proportionate reduction via an email to rdt@caiso.com by that date.

During the time that the issue is being investigated and resolved, the resource owner(s) must work with their Scheduling Coordinator (SC) to ensure that the output of the resources within the aggregate capability constraint does not exceed the aggregate capability constraint limits.

If the issue either cannot be resolved within the fourteen (14) calendar days or the resource cannot demonstrate the capability to not exceed the aggregate capability constraint during the investigation and resolution period, the CAISO may implement a pro-rata cut to the PMax values in the Master File for the resources within the aggregate capability constraint.

3.1.14.1.1 Impact of VER Certification Process and Aggregate Capability Constraints

When a VER is in Stage 2 status and does not have a reliable forecast, it is classified as unable to comply with dispatch instructions and must self-schedule. A resource that is unable to comply with dispatch instructions will have its DOT determined by its telemetered output. A Stage 2 VER may be co-located with another resource that can provide ~~both~~ energy, ~~and~~ Ancillary Services, Imbalance Reserves, and Reliability Capacity. In the Fifteen-Minute Market, the Stage 2 VER can be awarded its self-schedule and the other co-located resource can be awarded a combination of energy, Ancillary Services, Imbalance Reserves, and Reliability Capacity ~~energy and Ancillary Services~~ that does not exceed the ACC limit. However, if the output of the Stage 2 VER exceeds the self-schedule submitted in the Fifteen-Minute market, the combined energy, Ancillary Services, Imbalance Reserves, and Reliability Capacity ~~energy and Ancillary Services~~ provided from the co-located resources potentially could exceed the ACC limit. The Ancillary Service that was awarded on the other co-located resources in the Fifteen-Minute Market cannot be rescinded by the five-minute real-time market dispatch. The SC for these co-located resources must schedule and output a combination of energy and Ancillary Services during this Stage 2 VER timeframe to ensure the ACC limit is not violated.

When the solar/wind co-located resource becomes a Stage 3 VER, a forecast will be used to determine the Fifteen-Minute Market schedule and five-minute DOT. If the combination of RTD forecasted energy on the solar/wind co-located resource and energy, Ancillary Services, Imbalance Reserves, and Reliability Capacity ~~energy and Ancillary Services~~ on the other co-located resource exceeds the ACC limit, then the DOT of the co-located VER may be curtailed to stay within the ACC.

3.2 Locational Marginal Prices

3.2.1 LMP Disaggregation

3.2.2 System Marginal Energy Cost

3.2.3 Marginal Cost of Losses

3.2.4 Marginal Cost of Congestion

3.2.5 Flexible Ramp Up/Down Marginal Pricing

3.2.6 Reliability Capacity Pricing

Reliability Capacity Marginal Prices (RCMPs) are the marginal costs of procuring the last MW of Reliability Capacity Up (RCU) or Reliability Capacity Down (RCD) at a specific PNode in the RUC process. Similar to the LMP for Energy, the RCMP is calculated for each PNode and is comprised of three distinct components: a system marginal energy cost for the reliability product, a marginal cost of losses, and a marginal cost of congestion.

The three components are defined as:

1. System Marginal Reliability Cost: This is the energy component of the RCMP and reflects the marginal cost of procuring the last MW of RCU or RCD from a system-wide perspective. It is derived from the shadow price of the RUC power balance constraint and is the same for all PNodes.

2. Marginal Cost of Losses: This component accounts for the marginal cost of transmission losses associated with delivering Reliability Capacity from a specific PNode to the reference location. It is calculated as the product of the System Marginal Reliability Cost and the Marginal Loss Factor for the resource from the RUC run.

3. Marginal Cost of Congestion: This component reflects the cost of network congestion related to the Reliability Capacity award. It is calculated as a linear combination of the shadow prices of all binding transmission constraints in the RUC run, each multiplied by the resource's corresponding Power Transfer Distribution Factor.

Resources awarded RCU or RCD are paid the respective RCMP at their PNode.

3.2.7 Imbalance Reserve Pricing

Imbalance Reserve Marginal Prices (IRMPs) are the marginal costs of procuring the last MW of Imbalance Reserves Up (IRU) or Imbalance Reserves Down (IRD) at a specific PNode. The IRMP is calculated for each Trading Hour in the IFM and is specific to each PNode.

Similar to the LMP for Energy, the IRMP is composed of a system-wide energy component and a locational congestion component. Unlike the LMP for Energy, the IRMP does not include a Marginal Cost of Losses component. The two components are:

1. System Marginal Imbalance Reserve Cost: This is the energy component of the IRMP. It is derived from the shadow price of the system-wide IRU or IRD procurement constraint, which reflects the marginal bid price for the respective product. This component is the same for all PNodes.

2. Marginal Cost of Congestion: This component reflects the cost of network congestion related to the Imbalance Reserve award. It is calculated as a linear combination of the shadow prices of binding transmission constraints in the IRU and IRD deployment scenarios, each multiplied by the resource's corresponding Power Transfer Distribution Factor.

Resources awarded IRU or IRD are paid the respective IRMP at their PNode.

4. Ancillary Services

4.1 Ancillary Services Regions

4.2 Ancillary Services Requirements

The requirements for Ancillary Services (AS) are determined by CAISO in accordance with the applicable WECC and NERC reliability standards.

AS Bids from resources internal to the CAISO Balancing Authority Area do not compete for the use of the transmission network in the market optimization applications. Rather, AS is procured on a regional basis, where the AS Region is defined as a set of PNodes, including Scheduling Points, on the FNM. The CAISO may set minimum and maximum procurement limits for each AS Region, for each service, and for each hour, to ensure Local Reliability Criteria are met.

Accordingly, the CAISO establishes minimum AS requirements for the "Expanded System Region," for each AS type, taking into consideration:

- Loads and generation Path Contingency deratings
- Path Total Transfer Capability (TTC)
- Largest single Contingency (on-line Generating Unit)

CAISO may establish minimum and/or maximum AS procurement limits for each AS Region, taking into consideration one or more of the following factors:

- Loads and generation Path Contingency deratings
- Path TTCs
- Largest single Contingency (on-line Generating Unit or in-service transmission)
- Forecasted path flows
- Other anticipated local operating conditions for Load and/or Generation pocket AS Regions

The minimum AS limit for the Expanded System Region reflects the quantities of each Ancillary Service required to meet the applicable WECC and NERC reliability standards for the CAISO Balancing Authority Area. Under the prior standards, at least 50% of contingency reserves had to be Spinning Reserves. WECC has eliminated the requirement that a Balancing Authority maintain at least 50 % of its contingency reserves as Spinning Reserve. The CAISO will continue to procure Spinning Reserve but its target procurement may be less than 50% of its contingency reserve requirement.

The minimum procurement limit for AS in the System Region, which is defined as the Expanded System Region minus the System Resource at Scheduling Points, is set to a proportion of the minimum procurement limits of the Expanded System Region. The current default is 50%, which may be changed based on system conditions and CAISO Operator decision. The CAISO posts the AS requirements and results for each System Region in the Day Ahead and Real Time timeframes.as well as the percentage of procurement limit from imports.

In addition to the System and Expanded System Regions, the procurement limit(s) for any given AS Region may be:

- **Zero (or infinity for maximum limit)** – Indicating that there are no expected limitations, associated with the transmission path(s) adjoining the AS Region to other AS Regions, on the deliverability of AS procured system-wide; or

- **Non-zero** – Such a limit is based on factors that have a direct effect on the system constraint for which the AS Region was intended to manage.

For a given AS Region in a given interval, if the maximum total upward AS limit is set to a value less than the sum of the minimum limits for individual upward AS types, then the maximum total upward AS limit will be relaxed, if necessary, to uphold the minimum procurement limits for individual AS types. Otherwise, the total upward AS limit can bind simultaneous with binding minimum limits for individual upward AS types.

The CAISO considers the following factors when establishing a minimum or maximum limit for each AS sub-Region:

- The CAISO Forecasts of CAISO Demand
- The location of Demand within the Balancing Authority Area
- Information regarding network and resource operating constraints that affect the deliverability of AS into or out of a AS sub-Region
- The locational mix of generating resources
- Generating resource outages
- Historical patterns of transmission and generating resource availability
- Regional transmission limitations and constraints
- Transmission outages
- Available Transfer Capacity
- Day-Ahead Schedules or RTM Intertie Schedules
- Whether any Ancillary Services provided from System Resources requiring a NERC tag fail to have a NERC tag
- Other factors affecting system reliability

The determination of a sub-Regional minimum procurement related to a transmission outage is based on the N-1 TTC of the path minus the expected N-0 flow on the path, where the expected N-0 flow on the path is determined from previous market solutions for similar conditions. The N-1 TTC of the path is the effective TTC of the path when the single largest Contingency is taken on an element of that path.

For example, consider a path that is comprised of three transmission lines, and which has a normal TTC of 1000 MW. For a particular hour of the next day's market, the expected flow is 800 MW, which is below the N-0 TTC. However, if the system experiences a loss of one of the lines that comprise this path, the N-1 TTC of the path is de-rated to 500 MW. Therefore, the impact of supplying Energy to CAISO Demand for an N-1 Contingency on this path is 300 MW, since the 800 MW of N-0 flow must be reduced to 500 MW for that Outage.

If the CAISO changes its rules to determine minimum procurement requirements for Regulation Down, Non-Spinning Reserve, Spinning Reserve and Regulation Up, the CAISO will issue a Market Notice to inform Market Participants.

4.2.1 Self-Provided Ancillary Services

4.2.2 Conversion of Conditionally Qualified SPAS to Energy

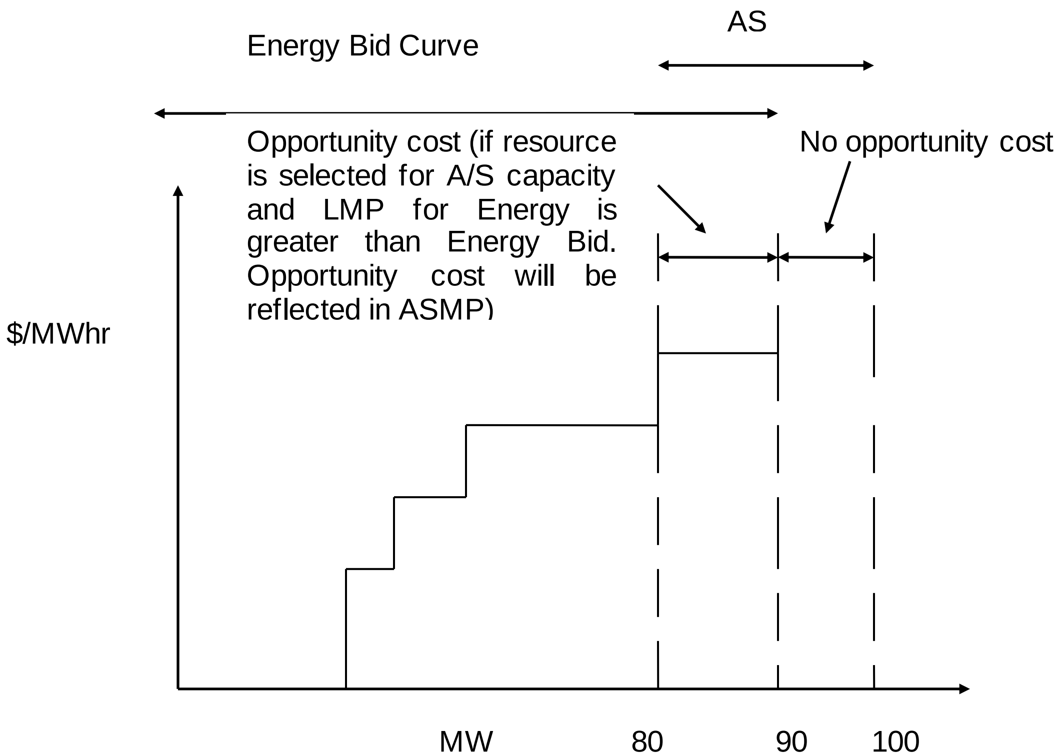
4.2.3 Conversion of Conditionally Unqualified SPAS to Qualified SPAS

4.2.4 Other Details of SPAS

4.3 Ancillary Services Procurement

The bidding rules for AS procurement are as follows:

- All AS Bids (not Self-Provided) may be accompanied by an Energy Bid in DAM, and must be accompanied by an Energy Bid in RTM, which are used as the AS Bid is considered in the AS selection process (which is part of the simultaneous Energy, AS, and Congestion Market Clearing process). Only exception to this is Capacity that is awarded Regulation. Energy Bid is optional in RTM in the case of Capacity that is awarded Regulation except for MSS load-following resources. If an AS Bid in DAM is included and the Energy Bid does not extend to the full available capacity of the resource, then all or part of the AS Bid is considered to use available capacity that is not covered by the Energy Bid, and no opportunity cost is considered in the co-optimization of Energy and AS. For example, let's assume there is a resource with a Pmax of 100 MW. It provides an Energy Bid of 90 MW and AS Bid of 20 MW in DAM. The software will co-optimize until 90 MW of capacity. It will calculate if it has to use 80 MW of Energy and 20 MW of AS or 90 MW of Energy and 10 MW of AS, if it has to use this resource at all depending on the economics of the bid. Any AS Bid beyond the Energy Bid Curve has zero opportunity cost. In this case, the last 10 MW of AS bid has zero opportunity cost. See the bid curve below. The portion of the awarded AS capacity that is covered by an Energy Bid has a non-zero opportunity cost only if the total resource capacity is allocated between Energy and Ancillary Services, as would be in the case below if 80 MW of Energy were scheduled and 20 MW of spin were awarded.


AS
Energy Bid Curve
Opportunity cost (if resource is selected for A/S capacity and LMP for Energy is greater than Energy Bid. Opportunity cost will be reflected in ASMP)
No opportunity cost
$/MWhr
MW
80
90
100

- An Energy Bid is not required for AS that is Self-Provided in the DAM. However, an Energy Bid is required in RTM for DA Spin and Non-Spin awards. While Conditionally Qualified Self-Provided AS is included in the optimization, unconditionally qualified Self-Provided AS does not enter the optimization.

- In IFM, for Variable Energy Resources (VERs) with Energy and Ancillary Service bids, the bid-in maximum Energy MW will be used as the upper bound to limit awards of Energy, Spinning Reserve, Non-spinning Reserve and Regulation Up. In RUC, the VER forecast will be used as the upper bound for IFM Energy, IFM Spinning Reserve, IFM Non-Spinning Reserve, IFM Regulation Up and ~~RUC capacity~~Reliability Capacity. For the Real-Time Market, the VER forecast will be used to limit Energy, Spinning Reserve, Non-spinning Reserve and Regulation Up. If the sum of Energy and Ancillary Service awards is greater than the VER forecast, then Energy and Ancillary Services will be curtailed based on economic bids and penalty price for self-schedules.

The cost of procuring the AS by CAISO on behalf of the SCs is allocated to Measured Demand on a CAISO Balancing Authority Area basis.

The ISO procures Ancillary Services from Multi-Stage Generating Resources at the MSG Configuration level.

4.3.1 Ancillary Services Procurement in Day-Ahead Market

CAISO procures 100% of its AS needs associated with the CAISO Forecast of CAISO Demand net of unconditionally qualified Self-Provided AS. AS Bids are evaluated simultaneously with Energy Bids and Imbalance Reserve Bids in the IFM to clear bid-in Supply and Demand. Thus, the IFM co-optimizes Energy, ~~and~~ AS, and Imbalance Reserves; the capacity of a resource with ~~Energy and AS Bids~~these bids is optimally used for an Energy schedule, or it is reserved for AS or Imbalance Reserve ~~in the form of AS~~ Awards. Furthermore, AS Bids from System Resources compete with Energy Bids and Imbalance Reserve Bids for intertie transmission capacity.

Energy Schedules, ~~and~~ AS Awards, and Imbalance Reserve Awards from System Resources are constrained over Interties. Therefore, the optimal Dispatch of Energy, ~~and~~ AS capacity, and Imbalance Reserve capacity can be accomplished by assigning the same Congestion cost to each commodity. This process allows Energy, ~~and~~ AS capacity, and Imbalance Reserve capacity to compete for the transmission access to (or from) the CAISO Balancing Authority Area directly, based on their Bids. This cannot be done for transmission internal to the CAISO Balancing Authority Area because the particular use of Ancillary Services in RTM is unknown during the AS procurement process. For this reason, Energy, ~~and~~ AS capacity, and Imbalance

Reserve capacity cannot directly compete for transmission across the internal CAISO Balancing Authority Area grid.

In the optimization of Energy and AS clearing, the limits on AS Regions are enforced as constraints represented by penalty prices in the application software, while Energy and AS are economically optimized subject to the AS Region procurement constraint(s).

AS are procured in the IFM to meet the AS requirements, net of qualified AS self-provision, subject to resource operating characteristics and regional constraints.

For Regulation Up and Regulation Down, Capacity and Opportunity Cost Bids are combined into a single bid which is co-optimized with Energy, Mileage, and other Ancillary Services. Additional constraints are added in the optimization problem to limit the Mileage awards for each resource with regulation capacity awards within a range based on the respective resource mileage multiplier. If economical, the optimization may procure Regulation from resources more likely to provide Mileage, i.e. have a higher resource Mileage multiplier, in order to meet the Mileage requirement. However, in general the optimization will not procure additional Regulation capacity in order to meet the Mileage requirement.

Because intertie transmission capacity must be reserved for AS Import Awards, AS Import Awards are charged with explicit Congestion charges when the relevant intertie is congested. For Energy Schedules, Congestion charges are included in the LMPs. However the ASMPs do not reflect congestion. For this reason, AS imports are charged with a separate Congestion charge that amounts to the AS Import Award multiplied by the shadow price of the relevant congested intertie. Regulation Up, Spinning Reserve and Non-Spinning Reserve are charged when the relevant intertie is congested in the import direction, whereas Regulation Down is charged when the relevant intertie is congested in the export direction. Unlike Energy imports and exports, AS imports are not paid when the relevant intertie is congested in the opposite direction because they do not create counter flow intertie transmission capacity.

Absent binding inter-temporal constraints (such as block energy constraints), the ASMP for a given AS and Import Resource minus the shadow price of the relevant intertie (in the appropriate direction) would be no less than the accepted AS bid price plus any opportunity cost.

Unlike other AS Awards, the Mileage procurement for Regulation Up and Regulation Down is not a financially binding award. Resources will be settled based on Adjusted Instructed Mileage as adjusted for accuracy. See the *BPM for Settlements and Billing* for more information.

4.4 Ancillary Services Marginal Prices

Generally speaking, the Ancillary Services Marginal Price (ASMP) for a given service at a given “location” is the cost of procuring an increment (MW) of that service at that location. It is, however, understood that the use of the word “location” here is not entirely precise because the “locations” where AS requirements are defined are AS Regions, whereas ASMPs are determined for individual PNodes.

This is a somewhat academic distinction, however, because in practice all PNodes belonging to the same set of AS Regions have the same ASMP. To better understand this statement, consider the AS Expanded System Region along with all of the AS Regions. Because some AS Regions have common areas (are nested), collectively they divide up the AS Expanded System Region into smaller areas. The ASMP for all PNodes within each of these smaller areas is the same.

ASMPs can be described more precisely in terms of Regional Ancillary Service Shadow Prices (RASSPs). RASSPs are produced as a result of the co-optimization of Energy, ~~and~~ AS, and Imbalance Reserves for each AS Region, and represent the cost sensitivity of the relevant binding regional constraint at the optimal solution, i.e., the marginal reduction of the combined Energy-AS procurement cost associated with a marginal relaxation of that constraint.

The opportunity cost for a resource which is awarded AS rather than energy or Imbalance Reserves when the ~~energy~~ bid is otherwise competitive is not computed explicitly, rather it is implicit in RASSP for that AS Region.

If neither of the constraints (upper or lower bound) is binding for an AS Region, then the corresponding RASSP is zero. The ASMP for a given service at a particular PNode is the sum of all RASSPs for that service over all AS Regions that include that PNode. It thus follows that all PNodes located in exactly the same set of AS Regions have the same ASMP. For example, if the defined AS Regions with non-zero RASSPs consist of ”South of Path 26”, the System Region, the Scheduling Points, and the Expanded System Region, then all resources within “South of Path 26” have the same ASMP.

Exhibit 4-4 presents an example of how the RASSPs and ASMPs are related for a given set of the AS Regions. In this example the RASSPs are “given” from a pricing run for a specific AS product. The resulting ASMPs are for the PNodes within each AS Region.

Exhibit 4-4: Example for Spinning Reserve AS

AS Region	RASSP (Given)	ASMP @ PNode

AS Region	RASSP (Given)	ASMP @ PNode
South of Path 26	$20/ MW	20 + 10 + 5 = $35/MWh
System	$10/ MW	10 + 5 = $15/MWh
Expanded System	$5/ MW	$5/MWh

ASMP reflects any lost opportunity costs associated with keeping the resource capacity unloaded for AS instead of scheduling that capacity as Energy or Imbalance Reserves in the same market when the entire available capacity of a given resource is totally allocated among Energy, ~~and~~ AS Awards, and Imbalance Reserve Awards.

Regulation Up and Regulation Down Mileage Marginal Prices are published for the Expanded System Region only, since the Mileage requirements are set only for the Expanded System Region.

5. Existing Transmission Contracts, Converted Rights & Transmission Ownership Rights

6. Day-Ahead Market Processes

Welcome to the *Day-Ahead Market Processes* section of the CAISO *BPM for Market Operations*. In this section, you will find the following information:

- How CAISO determines and applies Market Power Mitigation
- How CAISO clears the Integrated Forward Market
- How CAISO performs the Residual Unit Commitment process

A timeline and data flow diagram is included for the Day-Ahead Market Processes, as shown in Exhibit 6-1, Day-Ahead Market Timeline.

6.1 Pre-Market Activities

There are many activities that take place in preparation for the DAM, as shown by the overview timeline in Exhibit 2-1 and as described in this section.

6.1.1 Congestion Revenue Rights

6.1.2 Full Network Model Build

6.1.3 Bid Information

6.1.4 Outage Information

6.1.5 CAISO Demand Forecast Information

6.1.6 Determine Total Transfer Capability

6.1.7 Before Day-Ahead Market is Closed

6.1.8 Overgeneration Condition

Overgeneration is a condition that occurs when there is more physical Supply that is scheduled and generating than there is physical Demand to consume the Energy.

In IFM, Overgeneration is managed as part of the IFM Unit Commitment process. However, IFM cannot de-commit self-scheduled resources. Overgeneration condition in IFM may manifest when self-scheduled supply exceeds total bid-in demand. In this case, overgeneration will be resolved by reducing self-scheduled generation through the adjustment of non-priced quantities pursuant to the scheduling priorities specified in Section 31.4.

It is possible that the scheduled Demand in DAM has been over-scheduled relative to the forecast or actual Demand. Additionally, circumstances may occur where large amounts of Virtual Demand Awards cause an excess of physical Supply to be scheduled in IFM relative to the CAISO Forecast of CAISO Demand. ~~If the scheduled CAISO Demand exceeds the CAISO Forecast of CAISO Demand when performing RUC, RUC may reduce supply scheduled in IFM down to minimum load through uneconomic adjustments but RUC does not automatically de-commit a resource scheduled in IFM.~~In these situations, the RUC process will procure Reliability Capacity Down (RCD) to provide the necessary downward dispatch capability. RCD awards create a reliability schedule that is lower than the resource's Day-Ahead Schedule, but RUC will not de-commit a resource that was committed in the IFM. The CAISO Operator may communicate the need for future de-commitment of resources with affected Market Participants if a significant oversupply condition persists.

It is also possible that an excessive amount of Virtual Supply versus Virtual Demand is cleared in IFM, such that there is "virtual" overgeneration. Since RUC only runs with physical Bids and CAISO Forecast of CAISO Demand, and to the extent that Virtual Supply has displaced physical Supply, RUC may need to commit more physical resources and/or award more ~~RUC capacity~~Reliability Capacity Up (RCU) ~~maybe awarded~~ in order to make sure that there is enough physical capacity covering the CAISO Forecast of CAISO Demand.

If the scheduled CAISO Demand exceeds the CAISO Forecast of CAISO Demand when performing FMM, the CAISO uses the opportunity to deal with Overgeneration by economically clearing an Export Bid in FMM, in order to avoid manual intervention to decrease generation in Real Time.

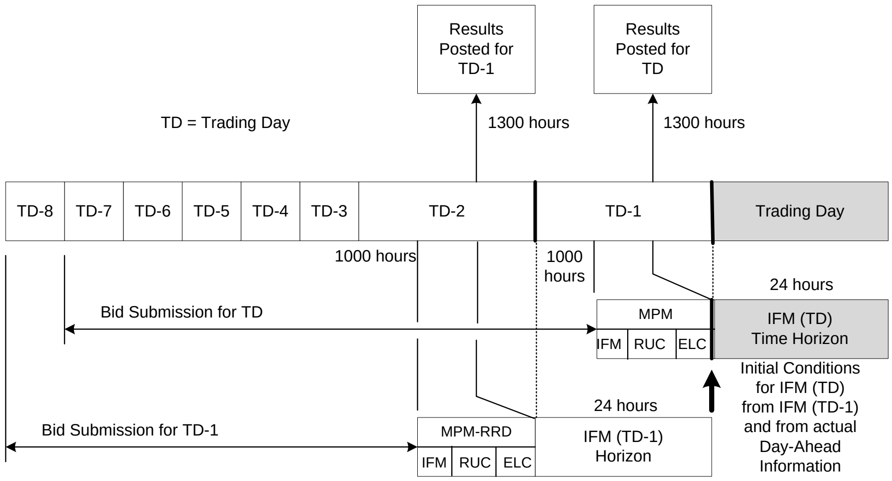
If the Overgeneration condition continues in Real-Time, RTM attempts to dispatch resources down using economic Bids to the extent possible to relieve the Overgeneration condition. If use of economic Bids is insufficient, then supply curtailment is performed through uneconomic adjustments in the order established in accordance with Section 34.12.2 of the CAISO Tariff. Additionally, RTUC may optimally de-commit resources in real time (refer to section 7). Lastly, Exceptional Dispatches may be necessary to resolve the Overgeneration condition including situations created by "virtual" overgeneration in the IFM due to Virtual Bidding. Exceptional Dispatches may also include manual resource de-commitment.

Detailed information can be found in Operating Procedure G202, Overgeneration.

6.2 Day-Ahead Market Timeline

The detailed Day-Ahead Market timeline is shown by Exhibit 6-1. ~~,~~ The Day-Ahead Market consists of four sequential passes: an IFM Market Power Mitigation (MPM) pass, the Integrated Forward Market (IFM), a RUC Market Power Mitigation pass, and the Residual Unit Commitment (RUC).~~showing the execution of the principal application functions, i.e., MPM, IFM, and RUC.~~ Each of these applications is described in detail in later sections of this BPM.

Exhibit 6-1: Day-Ahead Market Timeline



6.3 Scheduling Coordinator Activities

The SCs are the entities that interact directly with the CAISO Markets. They are responsible for submitting Bids into the CAISO Markets and to respond to the Dispatch Instructions and Unit Commitment Instructions of CAISO, resulting from the CAISO Markets.

6.3.1 Submit Bids

SCs submit Bids (for Supply, Virtual Supply, Demand, and Virtual Demand, Ancillary Services, Imbalance Reserves, and Reliability Capacity) for each resource to be used in DAM. DAM includes the ~~MPM, the~~ IFM and RUC, each with a corresponding MPM pass. SCs may submit Bids for DAM as early as seven days ahead of the targeted Trading Day and up to Market Close of DAM for the target Trading Day. CAISO validates all Bids submitted to DAM, pursuant to the procedures set forth in Section 30.7 of the CAISO Tariff. In the case of Virtual Bids (Supply and Demand), credit checks are performed against the Parent SC's (which provides financial collateral for itself and subordinate SCs) available credit limit prior to passing the Virtual Bids to the Day-Ahead Market.

SCs must submit Bids for RA Capacity into the IFM for Energy, Ancillary Services, and Imbalance Reserves, and into the RUC process for Reliability Capacity, as required in Section 40 of the CAISO Tariff. SC's obligations to submit bids for RA Capacity are described in detail in the BPM for Reliability Requirements.

To the extent that the SC wants to participate in any of the following markets, the following information must be submitted by the SCs before Market Close in order to participate in DAM:

- Energy Bids (Supply and Demand)
- Ancillary Services Bids
- Imbalance Reserve Up and Imbalance Reserve Down Bids
- ~~RUC Availability~~Reliability Capacity Up and Reliability Capacity Down Bids
- Self-Schedules
- Ancillary Services self-provision
- Virtual Energy Bids (Virtual Supply, and Virtual Demand)

Further details are given in the *BPM for Market Instruments*, Sections 5, 6 and 7

6.3.2 Interchange Transactions & E-Tagging

Consistent with NERC standards, SCs should submit E-Tags for DAM Schedules, which are due in DAM scheduling timeline, consistent with the WECC business practice and NERC standards in a manner that is not inconsistent with the CAISO Tariff.

The following types of DAM interchange transactions at Scheduling Points must be E-Tagged:

Ancillary Services Bids – For the capacity E-Tag, the Energy profile equals zero. However, the transmission allocation profile is equal to the awarded Bid. If the Ancillary Services capacity is converted to Energy, the tag's Energy profile is adjusted to the dispatched quantity.

Supply and Demand Bids and Self-Schedules

Consistent with WECC Regional Criterion, for CAISO Day Ahead awards of market priority type DALPT for which the CAISO is responsible for the contingency reserves, the corresponding E-Tag Energy Product Type shall equal Firm Provisional (G-FP[1]) and include the DALPT product-type in the MISC field. This properly communicates to the sink BA that if, in the event of a contingency to recover contingency reserves or in the event the CAISO is reducing these awards in HASP due to scheduling priorities in the

[1] G-FP: Firm Provisional Energy. This product may be interrupted only if the interruption is within the recall time and for conditions allowed by applicable provisions governing interruption of service, as mutually agreed to by the parties. A G-FP product cannot be interrupted for economic reasons.

CAISO BA, the E-Tag may be subject to adjustment based on the HASP award, or curtailment based on need following a contingency or resource deficiency in the CAISO consistent with tariff section 34.12.4. Day Ahead awards of market priority type DALPT are not to be combined with CAISO Real Time awards of market priority type RTLPT and RTECON. The MISC field on all G-FPs shall include the relevant market priority type (e.g., DALPT,).

CAISO Structural E-Tag Validation for G-FP Priority Types

- Failing to provide a valid MISC field indicator (e.g., DALPT, RTLPT, or RTECON) will result in CAISO denial of G-FP export tag on creation.

See Tariff Section 34.12.4. Misuse of the tagging protocol, or other actions to intentionally circumvent or otherwise avoid the priorities set forth in Section 12.4.3, are subject to monitoring and enforcement consistent with the terms of the CAISO tariff, including referral to the appropriate regulator as necessary.

Note that previously the CAISO required market priority types of DALPT and DAECON to be tagged separately, which indicated a Day Ahead award of lower priority determined economically in the Day Ahead market. We have eliminated the tagging requirement of DAECON since the DAECON market type is replaced with DALPT in HASP. DAECON market awards should be tagged as DALPT. Combining those DA tagging requirements in to one market priority relieves the Scheduling Coordinators of having to modify the E-tag market priority type after HASP. Real Time awards should not be combined with Day Ahead awards and are to be represented in separate tags with the appropriate priority type (e.g., RTLPT or RTECON).

➢ Provisions for G-FP Use In E-Tag Market Path “Product” field:

As provided in Section 34.12.4, curtailment is to be effectuated consistent with good utility practice and operator judgement. The G-FP tag allows the CAISO to utilize its tariff authority to

- restore contingency reserves following a contingency and deployment of existing contingency resources, where in the case where the re-procurement of contingency reserves is deficient.

- maintain reliability, including in an EEA3 condition, where armed load is utilized to restore deficient contingency reserves in conjunction with E-Tag curtailments, in order to maintain required contingency reserves.

TOR, ETC and CVR Self-Schedules

~~RUC capacity~~Reliability Capacity (RCU/RCD) is not tagged. Energy associated with a ~~RUC~~ Reliability Schedule dispatched on at an Intertie is to be tagged as Energy and not capacity consistent with the NERC standards.

To enable CAISO to match and validate the E-Tags with the corresponding market reservations, the following market information must be included on each E-Tag in the Misc. Information field of the Physical Path:

Energy Type: ENGY,SPIN or NSPN

Transmission Right Identifier, i.e., Contract Reference Number (CRN), applicable to ETC/TOR/CVR self-schedules.

Resource ID/ Transaction ID

Market Priority Type (DALPT, RTLPT, RTECON)

In addition, the CAISO will perform structural validation to ensure all scheduling coordinators enter in the E-Tag Market Path G-FP (Generation-Firm Provisional) in "Product" field for all CAISO low Market Priority Types (e.g., DALPT, RTLPT, RTECON)

Notes

An export resource ID can be associated with more than one market priority types with a MW corresponding to each market priority type. However, only one E-Tag can be used per Market Priority Type, as there is only one MISC field available in the tag for the priority type.

If an E-Tag is submitted and approved in the DAM time frame, the E-Tag is approved with a disclaimer. If ~~DAM~~ RUC results clears at a lower MW value than the Energy Profile, the E-Tag Energy Profile should be adjusted down by the Scheduling Coordinator to match the ~~RUC Day-Ahead~~final Reliability Schedule ~~schedule~~ as soon as possible after RUC Final Schedule publication. Where the Scheduling Coordinators fail to do so, the CAISO may adjust E-tags unilaterally with all entities on the tag promptly accepting the CAISO's adjustments. Failures to timely adjust, or accept the CAISO's adjustments, will be monitored and enforced consistent with the terms of the CAISO tariff, including referral to the appropriate regulator as necessary.

The CAISO has implemented a process to automatically adjust Day Ahead E-Tags to the match the Energy Profile to the RUC Final Schedule, which executes every day at both 15:30 and 17:30. On a typical day where RUC Final Schedules are published by 13:00, or upon rare occasion as late as 15:30, this is sufficient time for Market Participants to review their RUC Final schedules and E-Tag accordingly. DA Market for TD (xx/xx) is delayed and final results are expected to be published by (xx:xx). E-Tag auto adjustments in the DA timeframe that normally occur at 15:30 each day will be postponed to (xx:30).

Should a Day Ahead self-schedule or economic bid clear Day Ahead (IFM) but is adjusted in RUC, the portion that was RUC-adjusted may be re-offered in Real Time. However, to avoid the potential adjustment at 15:30 or 17:30 of both the original Day Ahead award and the Real Time award, a different Resource_ID and Transaction_ID should be used. This issue could also occur at XX:20 each hour in Real Time.

Example:

1. Day Ahead (IFM) DALPT of 100 MW
2. RUC awards 50 MW due to transmission constraint or load forecast requirements.
3. The DALPT tag of 100MW is adjusted to 50MW at 15:30
4. The re-submitted 50MW is awarded RTLPT.

To avoid an E-tag adjustment at 17:30 of both tags prorata to 25 MW, the market participant should E-tag and bid with a different Resource_ID and Transaction ID.

6.4 CAISO Activities

CAISO performs the following activities, described in the following sections, in the context of the DAM:

6.4.1 Accept Day-Ahead Market Inputs

6.4.2 Disseminate Pre-Market Information

6.4.3 Disseminate Post Market Close Information

6.4.4 Procedures for Closing the Day-Ahead Market

6.4.5 Execute Day-Ahead Market Applications

6.4.6 Publish Reports to Scheduling Coordinators

The following is a summary of the Day-Ahead reports available to SCs for online viewing after the DAM has completed its execution[5]:

- **Day-Ahead Generation Market Results** – Schedules of all generating resources.
- **Day-Ahead Load Market Results** – Schedules of both Participating Loads and Non-Participating Loads from the DAM.
- **Convergence Bid Clearing Results** – Virtual Supply Awards and Virtual Demand Awards from the IFM.
- ~~**Day-Ahead RUC Capacity** – Incremental capacity amount committed or scheduled in the RUC, above the Day-Ahead Schedule.~~**Day-Ahead Reliability Capacity Up (RCU) Awards** – Incremental capacity amount awarded in the RUC process above the Day-Ahead Schedule.
- **Day-Ahead Reliability Capacity Down (RCD) Awards** – Decremental capacity amount awarded in the RUC process below the Day-Ahead Schedule.
- **Two Day-Ahead Residual Unit Commitment (RUC) Advisory Schedules** – Advisory RUC schedules produced from the second trade day of the two Day-Ahead market run.
- **Day-Ahead Import/Export Schedules** – Import and export Schedules from the DAM.
- **Day-Ahead Start-Up & Shutdown Instructions** – Commitment instructions of all resources from the DAM.

[5] Note: the SC's confidential information is available only to the SC.

- **Day-Ahead Ancillary Services Awards from accepted Bids and qualified Self-Provision** – Awards for AS MW quantity, by AS type and resource from the DAM.

- **Day-Ahead Imbalance Reserve Awards** – Awards for IR MW quantity, by IR type and resource from the IFM.

- **Day-Ahead MPM Results** – Information about the "Mitigated" Bid that is used if the original Bid is modified in the MPM process. In addition the following MPM results will be published for informational purposes: LMPs at all PNodes and Apnodes with market resources associated with physical bids; shadow prices for all binding constraints; competitive path determination for all binding constraints; and reference bus identification.

- **Non-Participant Price Curves** – Information on the Default Energy Bids supplied by an independent entity used in MPM. Day-Ahead Inter-SC Trades – Inter-SC Trade schedules for both Inter-SC Trades at Aggregate Pricing Nodes and Physical Trades , for both Inter-SC Trades of IFM Load Uplift Obligation and Ancillary Services from the DAM

- **Day-Ahead Resource Energy Prices –** Resource-specific (LMPs and ASMPs).

- **Day-Ahead Resource Ancillary Service Prices –** Resource- specific ASMPs.

- **Self-Provided AS Awards**.

- **Day-Ahead Unit Commitments** - Resources that are self-committed or CAISO committed by the IFM or RUC process in the Day-Ahead Market

- **Default RMR Minimum Load & Startup Cost Bid Curves** - Default Minimum Load and Start-Up cost bid curves used in the Market Power Mitigation process. This applies to LRMR (Legacy RMR) units only.

- **Day-Ahead LMPs at all Pnodes for informational purposes.**

- **Extremely Long-Start Resource Startup Instructions** - Startup instructions resulting from the Extremely Long-Start Commitment (ELC) process.

- **Day-Ahead Reliability Must Run (RMR) Dispatches** – LRMR units that either have an energy schedule (from the IFM run) and / or an RMR dispatch

- **Conformed Dispatch Notice (CDN)** - Summary of the Day-Ahead Energy Schedules, Ancillary Service Awards, RMR Dispatches, Competitive Constraint Run results of RMR resources. This is available on CMRI.

- **Shadow prices for the interties –** Shadow prices for the interties are available in OASIS.

- **Volume of Virtual Awards** - System wide total Virtual Supply Awards and Virtual Demand Awards

- **Maximum MW limit per Eligible PNode and Eligible APNode** – Maximum nodal MW limit used to apply the Position Limits to Virtual Bid

- **Hourly Prices due to Convergence Bidding for CRR Adjustment Report –** Hourly LMP differentials between Day-Ahead Market and Real-Time Market used for CRR revenue adjustments caused by Virtual Bids under the CRR Settlement Rule.

- **Binding Transmission Constraints due to Convergence Bidding for CRR Adjustment Report –** Provides listing and status of PNodes associated with transmission constraints and whether their binding constraints were due to Virtual or physical Bidding activity in IFM. This report provides support information for CRR revenue adjustments applied under the CRR Settlement Rule.

- **Flow Impact Due to Convergence Bidding for CRR Adjustment Report -** Reports hourly MW flow contributions for transmission constraints impacted by SCs submitting Virtual Bids on behalf of a Convergence Bidding Entity that is also a CRR Holder. This report provides support information for CRR revenue adjustments applied under the CRR Settlement Rule.

Refer to the *BPM for Market Instruments, Sections 10 and 12* for the detailed contents of these records.

6.4.7 Resource Commitment

The commitment of resources by the Day-Ahead and Real-Time applications is shown in Exhibit 6-2[6].

Exhibit 6-2: Generating Unit Commitment Selection by Application

[6] For RA bidding obligations the definition of fast, short medium and long start resources is solely based on the start-up time. Please see the BPM for Reliability Requirements and definitions in Appendix A of the Tariff.

Attribute	Short Start	Long Start	Extremely Long-Start
Start Up Time / Cycle time[7]	Cycle Time Zero to 255 minutes	Cycle Time greater than 255 minutes and Start-Up Time less than or equal to 1080 minutes	Start-Up Time greater than 1080 minutes
Day-Ahead Applications			
IFM	Commit (financial)	Commit	No Commit
RUC	Advisory	Commit	Advisory Commit
ELC[8]	Advisory	Advisory	Commit
Real-Time Applications			
RTUC	Commit/ Advisory	No Commit	No Commit
STUC	Commit/ Advisory	No Commit	No Commit

Note: A Short Start or Long Start Unit can also be qualified for providing Non-Spinning Reserve if its start up time is less than 10 minutes.

6.5 Market Power Mitigation for IFM

The market power mitigation process is used to identify which scheduling coordinators can exercise local market power in circumstances where there are insufficient resources to rely on competition to mitigate constraints based on market bids. In the absence of sufficient resources to rely on competition, scheduling coordinators could potentially manipulate the energy price or imbalance reserve price in their local area by economically withholding supply. Any scheduling coordinator that is identified through this process will be subject to bid mitigation for its energy and imbalance reserve up bids. ~~.~~

The MPM process will consist of a single market optimization run in which all modeled transmission constraints are enforced. It will utilize the same market optimization engine as

[7] Cycle time is start up time plus minimum run time from the MasterFile. For resources that have registered a start up curve, the longest start up time shall be used to determine cycle time. For MSG resources, plant level data shall be used.

[8] Extremely Long Start Commitment Process

used in the CAISO's IFM and RUC. Some characteristics of DAM LMPM are summarized as follows:

- The MPM process occurs in DAM immediately after the DAM close of bidding at 10:00 AM, by when all Bids and Self-Schedules are submitted by the SCs and validated by CAISO.
- The Time Horizon for MPM in DAM is 24 hours (23 and 25 respectively on Daylight Saving transition days).
- Each market interval for MPM in DAM is one hour.
  - The time resolution of the CAISO Forecast of CAISO Demand in DAM is hourly.
  - The Energy Bid and Imbalance Reserve Up Bid mitigation in DAM is performed on an hourly basis.
- Virtual Bids and Bids from Demand Response Resources, Participating Load, Hybrid Resources, and non-storage Non-Generator Resources[9] are considered in the MPM process as part of the power balance equation. However, these bids are not subject to mitigation. Bids from resources comprised of multiple technologies that include Non-Generator Resources will remain subject to mitigation. Imbalance reserve up bids from non-EDAM intertie resources are not subject to mitigation. Imbalance reserve down bids are not subject to mitigation.
- Multi-Stage Generating Resources will be subject to the market power mitigation procedures described in Section 31.2 of the CAISO Tariff at the MSG Configuration basis as opposed to the overall plant level.

6.5.1 Decomposition method

The MPM method is referred to as the locational marginal price decomposition method (or LMP decomposition method). ~~It~~ The MPM process consists of a single market optimization run in which all modeled transmission constraints are enforced in the base scenario, the imbalance reserve up deployment scenario, and the imbalance reserve down deployment scenario. The binding transmission constraints in these scenarios are evaluated for competitiveness.

[9] Some storage resources are also exempt from mitigation as described in section 6.5.6 of this BPM.

~~Then~~After the market optimization, each LMP in the market is ~~be~~ decomposed into four components: (1) the energy component; (2) the loss component; (3) the competitive congestion component; and (4) the non-competitive congestion component. For location i:

$$LMP_i = LMP_i^{EC} + LMP_i^{LC} + LMP_i^{CC} + LMP_i^{NC} \quad ,$$

where

- EC stands for the energy component,
- LC stands for the loss component,
- CC stands for the competitive constraint congestion component (Competitive LMP), and;
- NC stands for the non-competitive constraint congestion component.

Under the LMP decomposition method, a positive non-competitive congestion component indicates the potential of local market power. Energy and Imbalance Reserve Up (IRU) Bids from any such resources will be subject to mitigation.~~The non-competitive congestion component of each LMP will be calculated as the sum over all non-competitive constraints of the product of the constraint shadow price and the corresponding shift factor.~~

- Energy Bids: An energy bid from a resource that can provide counter-flow to an uncompetitive constraint is subject to mitigation if that constraint is determined to be uncompetitive in the base scenario, the upward deployment scenario, or the downward deployment scenario. The bid is mitigated to the higher of the resource's Default Energy Bid (DEB) or the competitive LMP. The competitive LMP is the LMP at the resource's location minus the non-competitive congestion component.

- Imbalance Reserve Up (IRU) Bids: An IRU bid from a resource that can provide counter-flow to an uncompetitive constraint is subject to mitigation if that constraint is determined to be uncompetitive in the upward deployment scenario. The bid is mitigated to the higher of the Default Availability Bid (DAB) or the competitive marginal price for IRU.

    - The Default Availability Bid is a static, system-wide value for imbalance reserves, distinct from the DEB for energy.

    - The competitive marginal price for IRU is the marginal price of IRU at the resource's location minus the non-competitive congestion component from the upward deployment scenario.

In order for the non-competitive congestion component to be an accurate indicator of local market power, the reference bus that the shift factors relate to should be at a location that is least susceptible to the exercise of local market power. The CAISO selects as the reference bus the Midway 500kV bus when flow on Path 26 is north to south, and the Vincent 500kV bus when flow on Path 26 is south to north. The Midway and Vincent 500kV buses are excellent choices for LMPM purpose because they are located on the backbone of the CAISO's transmission system near the center of the California transmission grid with sufficient generation and roughly half the system load on each side. Therefore, these buses are very competitive locations, and are least likely to be impacted by the exercise of local market power. If the Midway and Vincent 500kV buses are disconnected due to an outage, a distributed load reference bus will be used.

~~Every resource with the LMP non-competitive congestion component greater than the Mitigation Threshold Price (currently set at zero) is subject to mitigation. Bids from any such resources will be mitigated downward to the higher of the resource's Default Energy Bid, or the "competitive LMP" at the resource's location, which is the LMP established in the LMPM run minus the non-competitive congestion component thereof (Competitive LMP~~ $\cancel{is\ LMP_i - LMP_i^{NC}}$ ~~).~~ A small configurable adder, which in all cases will be less than $0.01, is be added to the Competitive LMP.

6.5.2 Treatment of Legacy RMR Resources

All LRMR Resources are those with an RMR contract entered into prior to September 1, 2018, and remain under their LRMR contract. These contracts may have unique provisions for DA and RTM bidding, dispatch and settlements. All LRMR resources will be dispatched and settled according to the terms and conditions of their specific RMR contracts and Appendix H of the CAISO Tariff

6.5.2.2 **Treatment of RMR Resources**

RMR resources that are not LRMR are treated similarly to non-RMR resources in the LMPM process and have the same obligations and RA resources

6.5.3 Competitive Path Criteria

This is based on CAISO Tariff Sections 39.7.2.2 and 39.7.3.

As part of each MPM run, an in-line dynamic competitive/non-competitive designation calculation (dynamic competitive path assessment or DCPA) determines whether a constraint is competitive or non-competitive. A Transmission Constraint is competitive by default unless the Transmission Constraint is determined to be non-competitive as part of this calculation. ~~This will occur when the maximum available supply of counter-flow to the Transmission Constraint from all portfolios of suppliers that are not identified as potentially pivotal is less than the demand for counter-flow.~~

With the introduction of imbalance reserves, this assessment is performed for each binding transmission constraint in three distinct scenarios:

1. Base Scenario: Evaluates the competitiveness of constraints based on cleared bid-in load and physical energy schedules.
2. IRU Deployment Scenario: Evaluates the competitiveness of constraints under a scenario where Imbalance Reserve Up (IRU) awards are deployed.
3. IRD Deployment Scenario: Evaluates the competitiveness of constraints under a scenario where Imbalance Reserve Down (IRD) awards are deployed.

A Transmission Constraint is determined to be non-competitive if the test for local market power fails in any of these three scenarios. The test will fail when the maximum available supply of counter-flow from all portfolios of suppliers that are not identified as potentially pivotal is less than the demand for counter-flow.

The calculation of the demand for counter-flow is specific to each scenario:

- In the base case, it is based on the flow from physical energy schedules.
- In the upward deployment scenario, the demand for counter-flow considers the combined flow from both the physical energy schedule and the Imbalance Reserve Up (IRU) award.
- In the downward deployment scenario, the demand for counter-flow considers the flow from the physical energy schedule minus the Imbalance Reserve Down (IRD) award.

If, for some reason, the DCPA is unable to function, the MPM will rely on a default competitive path list that is compiled based on historical analysis of congestion and previous DCPA results on each Transmission Constraint.

The effect of enforcement of gas usage nomograms is not modeled in the DCPA. Therefore, the DCPA will not be able to account for the impact of reduced counter-flow from generators subject to nomogram constraints. When gas nomograms are enforced in the market, the CAISO will deem constraints as non-competitive when a gas nomogram is predicted to create conditions in which the maximum available supply of counter-flow to the Transmission Constraint from all portfolios of suppliers that are not identified as potentially pivotal is less than the demand for counter-flow on that constraint. First, the CAISO will identify the set of Transmission Constraints that can be relieved by counter-flow from potentially gas-limited resources. Then, the CAISO will estimate changes of the residual supply index (RSI) for each of those constraints resulting from gas nomograms of reflecting varying levels of restrictions on gas supply. Estimation of the RSI will involve identical calculations to the ones used in the market, but will use estimates of available capacity when a gas nomogram constraint is in place. The CAISO may designate a constraint or set of constraints non-competitive when the RSI is predicted to be non-competitive when a gas nomogram is imposed in the market.

Over time, the CAISO will develop a table that will identify the potentially non-competitive Transmission Constraints that CAISO operations may deem as non-competitive in the market based on imposition of a particular nomogram under various supply and demand conditions. For each constraint and nomogram combination, a limit or limits will be listed. If a gas nomogram is binding at a level listed on the table, it will be appropriate to declare the listed constraints non-competitive. The CAISO will continue to communicate data related to market power mitigation and the enforcement of gas usage constraints according to current procedures for both of these processes. A constraint deemed non-competitive through the manual override process based on the imposition of a gas supply nomogram will be included in the listings of constraints with competitive designation status provided on the CAISO OASIS site (http://oasis.caiso.com) in the reports MPM Nomogram/Branch Group Competitive Paths and MPM Intertie Constraint Competitive Paths. These reports are described in further detail in the BPM for Market Instruments, Section 12 Public Market Information.

For a detailed process description for the competitive path criteria, Refer to Attachment B.

6.5.4 Default Energy Bids

This section is based on CAISO Tariff Section 39.7.1, Calculation of Default Energy Bids.

Default Energy Bids (DEBs) are calculated daily for both the Day-Ahead and Real-Time markets. With the exception of the LMP-based DEB, the DEB does not vary by peak/off-peak period. The CAISO offers various methodologies to calculate DEBs for resources. Please refer to the BPM for Market Instruments, Attachment D for more information on each DEB methodology and sample calculations.

6.5.5 Default ~~Energy~~Availability Bids

A separate Default Availability Bid (DAB) is established for the mitigation of Imbalance Reserve Up (IRU) bids. This default bid is distinct from the DEB used for energy.

The Default Availability Bid is a static, system-wide value that serves as the mitigation "floor" for IRU bids across all resources and market intervals. This value is based on a high-percentile of historical spinning reserve bid prices to conservatively estimate a resource's cost to provide reserves. The introduction of the DAB provides a consistent reference point for IRU mitigation.

~~6.5.5~~6.5.6 Bid Adder for Frequently Mitigated Units

This section is based on CAISO Tariff Section 39.8.1, Bid Adder Eligibility Criteria.

To receive a Bid Adder for Frequently Mitigated Units, a Generating Unit:

- Must have a Mitigation Frequency that is greater than 80% in the previous 12 months
- Must have run for more than 200 hours in the previous 12 months
- Must not have an contract to be a Resource Adequacy Resource for its entire Maximum Net Dependable Capacity or be subject to an obligation to make capacity available under the CAISO Tariff

Additionally, the SC for the Generating Unit must agree to be subject to the Frequently Mitigated Unit Option for a Default Energy Bid. Run hours are those hours during which a Generating Unit has positive metered output.

~~6.5.6~~6.5.7 Mitigation Exemptions for Small Storage Resources

Storage resources less than 5 MW are not subject to market power mitigation.

~~6.5.6.1~~6.5.7.1 Enforcement of Constraints on the Interties

The CAISO enforces both scheduled and physical flows on the Interties through the use of a two-constraint approach. In the IFM, the ISO will continue to enforce a scheduling constraint and will include a physical flow constraint (based on the FNM expansion initiatives), each of which will consider both physical and Virtual Bids. To ensure uniqueness of prices, intertie constraints, similar to other transmission constraints, are formulated with additional slack variables. The scheduling constraint will continue to be based on the assessment of Intertie Bids submitted by the Scheduling Coordinators relative to the Available Transfer Capability of the specific Intertie location. This will ensure that contract paths are honored and will be used for E-Tagging intertie schedules. The physical flow constraint will be based on the modeled flows for the Intertie, taking into account the actual power flow contributions from all resource schedules in the Full Network Model against the Available Transfer Capability of the Intertie. Unlike the scheduling constraint, the contributions of intertie schedules towards the physical flow limit will be based on the shift factors calculated from the network model, which reflects the amount of flow contribution that change in output will impose on an identified transmission facility or flowgate. Each Intertie will have a single Total Transfer Capability and the scheduling limit and physical flow limit will be compared against the Intertie's capacity. The scheduling limit and physical flow limit are not necessarily equal to each other.

In the Residual Unit Commitment, the CAISO will enforce two constraints that only consider physical awards with respect to contract path limits

(*i.e.*, Virtual Awards cannot provide counterflow to physical awards).

~~6.5.6.2~~6.5.7.2 Maximum Daily Run Time

The maximum daily run time constraint enforces the maximum number of hours a resource can be committed on-line over the course of a calendar day. For resources that have this parameter, the IFM will limit commitment periods so that they do not exceed the hourly limitation. Commitment periods may or may not be consecutive. For resources that do not have this parameter set, the IFM may commit those resources for all hours in a day.

Market Participants may register this parameter in the Master File[10].

[10] Eligibility to register the parameter may be limited to resources which meet specific criteria. See BPM for Market Instruments Appendix Attachment B for details.

6.6 ~~6~~Integrated Forward Market

This section is based on CAISO Tariff Section 31.3, Integrated Forward Market.

After the MPM and prior to RUC, CAISO performs the IFM. The IFM performs Unit Commitment and Congestion Management, clears Virtual Bids submitted by SCs and clears the Energy Bids as modified in the MPM~~, taking into account transmission limits, inter-temporal and other operating constraints, and ensures~~. The IFM procures Ancillary Services based on Ancillary Service Requirements and also procures Imbalance Reserve Up (IRU) and Imbalance Reserve Down (IRD) products to meet upward and downward uncertainty requirements. The IFM co-optimizes energy, ancillary services, and imbalance reserves to produce financially binding day-ahead schedules and awards. The commodities procured in the IFM include:

- Energy from physical and virtual resources.
- Ancillary Services based on 100% of the CAISO Forecast of CAISO Demand.
    - RTPD may procure incremental additions to Ancillary Services in real-time
- Imbalance Reserve Up (IRU) and Imbalance Reserve Down (IRD) to meet upward and downward uncertainty requirements.

~~that adequate Ancillary Services are procured in the CAISO Balancing Authority Area based on 100% of the CAISO Forecast of CAISO Demand.~~

To ensure the deliverability of the Imbalance Reserve awards, the IFM includes deployment scenarios where these awards are modeled as deployed to meet the IRU/IRD requirements while all network constraints are enforced.

Note: All Flowgates and Nomograms that are active for energy enforce the IRU/IRD constraint by default. Activation of IRU/IRD may be unenforced on a case by case basis for individual constraints.

The IFM:

- Determines Day-Ahead Schedules for Energy, ~~and~~ AS Awards, and Imbalance Reserve Awards, and their related LMPs and ~~ASMPs~~marginal prices.
- Optimally commits resources that bid in to the DAM. The IFM performs ~~—~~an SCUC process which utilizes Mixed Integer Programming (MIP) algorithm using the multi-part Supply Bids (including a Start-Up Bid, Minimum Load Bid, and Energy Bid Curve), and ~~a~~ capacity ~~Bid~~ Bids for Ancillary Services and Imbalance Reserves, as well as Self-

Schedules submitted by SCs. The IFM also optimally schedules resources subject to their hourly Capacity Limits, and Use-Limited Resources subject to their submitted Daily Energy Limits. When making a commitment decision in IFM, consistent with the consideration of a resource's minimum up time that extends beyond the IFM trading day time horizon, the minimum load costs that extend beyond the IFM trade day horizon up to the resources minimum up time may also be considered.

- For a Multi-Stage Generating Resource, the IFM produces a Day-Ahead Schedule for no more than one MSG Configuration per Trading Hour. In addition, the IFM will produce the MSG Transition and the MSG Configuration indicators for the Multi-Stage Generating Resource, which would establish the expected MSG Configuration in which the Multi-Stage Generating Resource will operate. During a MSG Transition, the committed MSG Configuration is considered to be the "from" MSG Configuration.
- For Non-Dynamic System Resources, Energy and Ancillary Services awards are rounded to an integer value in order to comply with regional scheduling practices. The rounding will be performed in a way that the aggregate of schedules on an intertie do not violate the intertie limit.

6.6.1 IFM Inputs

In addition to the data identified in earlier sections of this BPM, this section lists those inputs that are particularly important in IFM:

- Ancillary Services requirements from AS requirements setter (see Section 4.2, Ancillary Services Requirements)
- **Imbalance Reserve requirements (IRUR/IRDR)**
- **Imbalance Reserve surplus and requirement distribution factors**
- Default LAP and Custom LAP Load Distribution Factors (see Section 3.1.4, Load Distribution Factors)
- Generation Distribution Factors (see Section 3.1.2, Generation Distribution Factors)
- Transmission constraints
- Generation Outages (see *BPM for Outage Management*)
- Daily total Energy Limits

- TOR/ETC capacity (see Section 5.2, Existing Transmission Contract Calculator)

6.6.1.1 Bids Usage & Treatment in IFM

The following Bids are considered in IFM:

- Energy Bids (multi-segment)
  - Three-part Energy Bids for Generating Resources (including Aggregate Generating Resources with specified Generation Distribution Factors)
  - Three-part Energy Bids for logical generators that represent Participating Loads in association with fixed (i.e., Price Taker), non-conforming Load Schedules
  - One-part Energy Bids for non-Participating Loads (including aggregated Loads with specified Load Distribution Factors)
  - One-part Energy Bids for System Resources (imports and exports)
  - One-part Energy Bids for Virtual Supply or Virtual Demand.

Three-part Energy Bids consist of Start-Up Cost (up to three segments), Minimum Load Cost (single value), and incremental Energy Bid (up to ten segments).

If the first Energy Bid MW breakpoint is higher than the Minimum Load, then there must be submitted Self-Schedules that add up to that MW level. The Self-Schedules between the Minimum Load and the first Energy Bid MW breakpoint are subject to uneconomic adjustments for Congestion Management based on artificial prices (penalties) that reflect various scheduling priorities.

Since Virtual Bids can be submitted per Eligible PNode/APNode for each eligible SC ID, in order to manage the volume of Virtual Bids into the IFM optimization, the following methodology will be utilized in SIBR and the IFM:

At the Day-Ahead Market close (currently 10:00 a.m.) the application will aggregate the Virtual Bids at each Eligible PNode/APNode to create one aggregate Virtual Supply Bid and one aggregate Virtual Demand Bid at each location (the aggregate bid can contain many more than 10 segments). For aggregation of Bids, the application will follow the standard of stacking up Bid segments when Energy Prices are different while adding MWs if Energy Prices are the same.

After the day-ahead application completes, the cleared Virtual Bid results will be de-aggregated at the eligible SC ID level before the Day-Ahead Market results, which include Virtual Awards, are published to Market Participants. For de-aggregation of a non-marginal segment, it is straight forward to assign the individual cleared MW to the eligible SCID. For the marginal segment, the relevant MW cleared amount may be associated with multiple bid segments and hence a prorating is needed to obtain the individual cleared MW amount at the SCID level. The CAISO will prorate the awarded MWs proportional to the submitted MWs of the marginal segment of each Virtual Bid contributing to the marginal aggregate segment.

- AS Bids (single capacity segment)
  - Regulation Up Bids (single segment capacity and price, single segment opportunity cost, and single segment Mileage price)
  - Regulation Down Bids (single segment capacity and price, single segment opportunity cost, and single segment Mileage price)
  - Spinning Reserve Bids
  - Non-Spinning Reserve Bids

AS may be simultaneously Self-Provided and Bid. AS Self-Provision from Non-Dynamic System Resources can be accomplished by submitting AS Bids at 0 $/MWH. AS exports are not allowed in the CAISO Markets.

- Imbalance Reserve Bids (single capacity segment)
  - Imbalance Reserve Up (IRU) Bids

  - Imbalance Reserve Down (IRD) Bids

Imbalance Reserve bids are single-segment hourly price-quantity pairs. A key condition for these bids is that a resource must also submit an economic Energy Bid for the capacity range that overlaps with its Imbalance Reserve bid.

6.6.1.1.1 Minimum Load Cost (MLC) adjustment under minimum load (Pmin) re-rate

If the Pmin of a resource or the Pmin of an MSG configuration is re-rated to a higher MW level than registered in Master File, the CAISO market systems consider the energy cost under the re-rated Pmin by adjusting the MLC to reflect the cost of commitment under the re-rated Pmin level. When optimizing MSG resources, the CAISO market will use the Default Energy Bid (DEB) associated with the resource to represent the actual cost of re-rating a configuration's Pmin with a Pmin re-rate. The DEB integration formula, shown below, is used to calculate the MLC' using the DEB integration method. The resulting MLC' will be used in commitment decisions by the market systems and in Bid Cost Recovery settlement (see next section).

DEB Integration Formula

$$MLC' = MLC + \int_{P_{min}}^{P_{min}'} DEB(p)dp$$

MLC' Minimum load cost of the re-rated Pmin level

MLC Minimum load cost of the original bid-in minimum load cost

DEB(p) Default energy bid cost associated with the actual cost of re-rating a resource or MSG configuration's Pmin

dp Change in energy

6.6.1.2 IFM Uplift Costs

The IFM Bid Cost for a given resource is due to the Start-Up Cost, Minimum Load Cost, Transition Costs, and Energy, ~~and~~ Ancillary Services, and Imbalance Reserve bid costs that are not otherwise recovered from the revenues associated with the IFM Energy and Ancillary Services markets. The IFM Bid Cost for all resources is recovered through the IFM Bid Cost Uplift.

The responsibility for the IFM Bid Cost Uplift can be transferred via Inter-SC Trades of IFM Load Uplift Obligation. It is important to understand that the responsibility for the IFM Bid Cost Uplift does not automatically transfer from one SC to another SC as a result of an Inter-SC Trade for Energy. Rather, if the agreement between the two trading SC's includes a provision that the IFM Bid Cost Uplift responsibility is to be transferred from the Energy buyer to the Energy seller, then a separate Inter-SC Trade of IFM Bid Cost Uplift must be submitted between the trading SCs.

Additional information on Bid Cost Recovery is given in the *BPM for Settlements & Billing*.

6.6.2 IFM Constraints & Objectives

Resources are committed and scheduled in the IFM for each Trading Hour of the Trading Day. Self-committed resources with Self-Schedules and/or Self-Provided AS are modeled as "must run" in the relevant Trading Hours. LRMR resources pre-dispatched manually before the DAM are also modeled as "must run" in the relevant Trading Hours with an RMR Self-Schedule at the applicable RMR level. Resources bidding in the market with 1) no startup or minimum load costs, 2) zero Pmin, and 3) zero startup time are considered always on-line from a commitment standpoint unless they have an Outage. These resources (NGRs by nature or resources registered this way in the Master File) are automatically available to receive an award of energy and/or AS unless there is an Outage.

Resources with Outages are modeled as “unavailable” in the relevant Trading Hours. Resources with multi-part Energy Bids and/or AS Bids, but without Self-Schedules or Submissions to Self-Provide an AS are modeled as “cycling” in the relevant Trading Hours, which means that these resources are available for optimal commitment in these hours, subject to applicable inter-temporal constraints and initial conditions. In particular, it should be noted that start up time is not included in the total Outage time. Startup time is considered to begin after the Outage has ended, thus the resource is not available for commitment until the startup time has elapsed as well.

The following ramping rules apply consistently for all DAM applications:

1) The resource’s Operational Ramp Rate would always be used to constrain Energy schedules across time intervals irrespective of Regulation Awards. The Operational Ramp Rate may vary over the resource operating range and it incorporates any ramp rates over Forbidden Operating Regions. The fixed Regulating Ramp Rate would only be used to limit Regulation awards.

2) Hourly Intertie resource schedule changes would not be limited across hours.

3) The upward and downward ramp capability of online resources across time intervals would be limited to the duration of the time interval: 60min in DAM.

4) The upward and downward ramp capability of resources starting up or shutting down across time intervals (from or to the applicable Lower Operating Limit) would be limited to half the duration of the time interval: 30min in DAM.

5) The upward and downward ramp capability of resources across time intervals would not be limited by capacity limits (operating or regulating limits); in that respect, the upward ramp capability would extend upwards to +∞ and the downward ramp capability would extend downwards to –∞ by extending the last and first segments of the Operational Ramp Rate curve beyond the resource Maximum Capacity and Minimum Load, respectively. Capacity limits would be enforced separately through the capacity constraints.

6) The upward ramp capability of resources across time intervals with Regulation Up and Imbalance Reserve Up (IRU) awards would be reduced by the sum of these awards over these intervals, multiplied by a configurable factor.

7) The downward ramp capability of resources across time intervals with Regulation Down and Imbalance Reserve Down (IRD) awards would be reduced by the sum of these awards over these intervals, multiplied by a configurable factor (same as above).

8) For each MSG Configuration, the Operational Ramp Rate curve is limited to two segments. These ramp rates will be used to determine the ramp capacity when the Multi-Stage Generating Resource is within the relevant configuration. The ramp time that it takes to transition from one configuration to another configuration is defined as the Transition Time per directional transition in the Transition Matrix.

These ramping rules result in a consistent unified treatment across all applications. Conditional ramp limits apply only to resources with Regulation awards. No ramp capability reduction is required for Spinning or Non-Spinning Reserve awards given that these awards are normally dispatched by RTCD where all ramp capability must be made available even at the expense of Regulation.

For resources with two regulating ranges, the IFM (and all other DAM applications) will use a single regulating range from the lower regulating limit of the first (low) regulating range to the upper regulating limit of the second (high) regulating range. This conservative approach is adopted because the ultimate regulating range within which the resource will operate in Real-Time is not known in advance in the DAM.

Also, CAISO will limit Operational Ramp Rate changes from one operating range to next operating range to a maximum 10:1 ratio. CAISO will internally adjust ramp rates to achieve a 10:1 ratio if submitted ramp rates exceed this ratio.

The Time Horizon of the IFM optimization is shown in Exhibit 6-1.

6.6.2.1 Multi-Stage Generating Resources in the Day-Ahead Market

- The IFM will dispatch Multi-Stage Generating Resources at the MSG Configuration level, determining the optimal MSG Configuration. Exceptional Dispatches, i.e., manual dispatches, will dispatch to a value for the specific Multi-Stage Generating Resources, but do not specify the particular MSG Configuration.

- The initial status for Multi-Stage Generating Resources is based on the registered individual MSG configurations and not at the Generating Unit or Dynamic Resource-Specific System Resources level (i.e., plant level). An MSG Configuration that is awarded in RUC at the end of previous Trading Day will receive from the CAISO their on-line initial status and corresponding initial MW for the next Trading Day. If there is no RUC Award for a Multi-Stage Generating Resource, then the MSG Configuration that was scheduled in IFM at the end of previous Trading Day will have the on-line initial status for the next Trading Day. Otherwise all the MSG Configurations would be treated as initially offline.

- Since Self-Provided Ancillary Services can be submitted only at the MSG Configuration for a given Trading Hour and since it is possible that that Multi-Stage Generating Resource can actually support the Self-Provided Ancillary Service amount from other configurations, Self-Provided Ancillary Service quantities are treated as plant level quantities in the Integrated Forward Market. In order to accomplish this, the Self-Provided Ancillary Services on the originally submitted MSG Configuration is propagated to other Ancillary Services certified MSG Configurations for the optimization to consider in the following steps:

  Step 1: Perform the Ancillary Services qualification process on the submitted MSG Configuration in the same manner as for non-Multi-Stage Generating Resources, except using the MSG Configuration's parameters such as ramp-rate, Minimum Load and PMax.

  Step 2: Transfer the qualified Ancillary Services self provision MW to other MSG Configurations with Ancillary Services certification in the same service product if these configurations have Energy Bids for that given Trading Hour. This transferred Ancillary Services self provision MW is determined by the following formula per transferred MSG Configuration,

  > Transferred Self-Provided Ancillary Services = Minimum (final qualified Self-Provided Ancillary Service of bid in MSG Configuration, certified Ancillary Services capacity of transferred MSG Configuration)

  Step 3: On the transferred MSG Configuration, the transferred Self-Provided Ancillary Services amount determined from step 2 will then be further qualified using the same rules in capacity and ramping qualification as for non-Multi-Stage Generating Resources (see section 4.2.1), except using the MSG Configuration's parameters such as ramp-rate, PMin and PMax.

- The Multi-Stage Generating Resource will be allowed to submit a Self-Schedule on only one MSG Configuration per given Trading Hour. However, this Self-Schedule reflects the Multi-Stage Generating Resource's intention to operate at or no lower than a certain MW level, not an intention to operate in a particular MSG Configuration. Consequentially, any one of the MSG Configurations may be committed if there is a self-schedule on any of the MSG Configurations within the same Multi-Stage Generating Resource. Once submitted, the Self-Schedule is associated with all MSG Configurations of the Multi-Stage Generating Resource that have a Minimum Load below or equal to the Self-Schedule quantity. In order to provide for fair economic choice among MSG

Configurations there will be adjustments to Start-Up Cost, Minimum Load Cost and related Transition Costs of affected configurations as listed below.

The rules given below apply to self-schedules:

1. For the MSG Configuration with a PMin higher than the Self-Schedule MW:
    - The Minimum Load Cost will be taken into account when considering commitment of the configuration, but will be reduced to only reflect cost of minimum load not consumed by Self-Scheduled quantity, i.e. will be equal to Max(0, Minimum Load Cost of the transferred configuration - Minimum Load Cost of the submitted MSG Configuration);
    - the Start-Up Cost will be taken into account when considering commitment of the MSG Configuration;
    - Transition Cost for any transition that is incident (incoming or outgoing) into/from the MSG Configuration will be considered unless conflicting with rules 2 and 3 below.
2. For the MSG Configuration with a PMin lower than or equal to the Self-Schedule MW and a PMax higher than or equal to the Self-Schedule MW:
    - Start-Up Costs and Minimum Load Costs are treated as must-run resources (i.e. there is no Start-Up Cost and no Minimum Load Cost);
    - Ignore Transition Costs for incoming transitions;
    - Consider Transition Costs for outgoing transitions.
3. For the MSG Configuration with a PMax lower than the Self-Schedule MW:
    - Ignore Start-Up Costs;
    - Minimum Load Cost treatment is the same as in (2) above;
    - Ignore Transition Cost for any transition incident to the particular configuration.

6.6.2.2 Group Constraint

The group constraint enforces a minimum time delay between two successive startups or two successive shutdowns within a group of resources. The minimum time delays will be enforced between any pair of resources within the group and no ordering is assumed among the resources in the group. There is no upward limit to the minimum time delay setting.

This constraint can be used for both generating and pump storage resources. Market Participants may define any set of their resources as a group, as long as the constraint represents an actual physical limitation of the group.

6.6.2.3 Stored Energy Management

This section describes how state of charge (SOC), which is measured in energy (MWh), is treated in the IFM run of the day-ahead market for NGRs designated as Limited Energy Storage Resources (LESRs). For information on state of charge management in the real-time markets, see section 7.8.2.5.

A storage resource will be subject to similar operational range limits as a traditional generator, with additional considerations to account for their unique operational characteristics. Unlike most traditional generators, storage is able to withdraw energy from the grid to charge, and have a limited energy storage capacity. The operating range of a storage resource is negative, to account for the ability to withdraw energy from the grid to charge. The model will account for a storage resource's charging efficiency when withdrawing energy from the grid. The charging efficiency is the percentage of charging energy that, after losses, is available for discharge. By convention, the state of charge for a given interval will be defined as the state of charge at the end of that interval.

The ability of a storage resource to provide energy and ancillary services will depend on state of charge.

The state of charge for a storage resource is governed by the state of charge equation as follows:

$$SOC_{i,t} = SOC_{i,t-1} - (EN_{i,t}^{(+)} + \eta EN_{i,t}^{(-)})\frac{\Delta T}{T_{60}}$$

$$\underline{SOC_{i,t}} \leq SOC_{i,t} \leq \overline{SOC_{i,t}}$$

$$SOC_{i,t}^{AT} = SOC_{i,t-1}^{AT} - (EN_{i,t}^{(+)} + \eta EN_{i,t}^{(-)} + ATRU_t RU_{i,t} - ATRD_t \eta_i RD_{i,t})\frac{\Delta T}{T_{60}}$$

$$\underline{SOC_{i,t}} \leq SOC_{i,t}^{AT} \leq \overline{SOC_{i,t}}$$

The state of charge equation is simultaneously enforced with the ancillary service impact and the ancillary service state of charge constraint as outlined in Section 4.2.9.2 of the Market Operations BPM.

6.6.2.3.1 State of Charge Constraints for Imbalance Reserves and Ancillary Services

To ensure the deliverability of awarded capacity, the IFM enforces State of Charge (SOC) constraints for storage resources. These constraints ensure a resource has sufficient energy to provide its awarded services.

The existing Ancillary Service SOC constraint is extended to include Imbalance Reserves. The market ensures that a storage resource has sufficient state-of-charge to sustain its awarded capacity for Ancillary Services (Regulation Up/Down, Spin) and Imbalance Reserves (IRU/IRD) for a specified duration (e.g., one hour in the Day-Ahead Market).

Furthermore, the market will generate a dynamic upper and lower boundary, or "envelope," for the state of charge of a storage resource. This envelope is designed to prevent the resource from being dispatched in such a way that its ability to provide awarded Imbalance Reserves is jeopardized. The envelope is tracked separately from the modeled SOC and is influenced by the IRU/IRD awards. If the hypothetical SOC reaches the envelope's upper or lower limit, the market will schedule the resource to charge or discharge as needed to preserve its ability to provide future services, before scheduling any further imbalance reserve capacity that would violate the envelope.

6.6.2.4 Minimum Online Commitment Constraint

The ISO has constraint modeling capability in the IFM and RTM to address the operational needs of operating procedures that require a minimum quantity of committed online resources in order to maintain reliability. These procedures specify requirements for a minimum quantity of online commitment from a specific group of resources in a defined area. This required minimum online commitment does not reflect a minimum energy production or an amount of 10 minute

operating reserve. Rather these requirements are described in terms of a minimum set of online resources, by name or by total quantity of operating capability based on the resources Maximum Operating level (Pmax) or an effective MW equivalent based on the units VAR support and/or location. However, the same set of resources committed in IFM to satisfy the minimum online constraint could also be ready for dispatch or be awarded ancillary services in the market co-optimization.

The ISO has adopted the following minimum online commitment method, which incorporates an additional nomogram type constraint equation capability into the market solution. In general, minimum online generation commitment (MOC) requirement is a constraint binding a group of market resources (generators) by the following relationship:

$$\sum_{i \in G} a_i \, Y_{i,t} \, P_{i,t}^{\max} \geq P_{G,t}^{moc} \qquad \forall t, G \qquad (1)$$

Where:

$P_{G,t}^{moc}$ is the minimum total online commitment required for interval t for the defined set of generating resources G.

a_i is a multiplier representing effectiveness for the resource i in meeting Minimum Online Commitment requirement

$Y_{i,t}$ is the commitment status for market resource i for interval t

$P_{i,t}^{\max}$ is the total maximum operating limit of the market resource i and interval t, as derated by SLIC of the resource (if appropriate)

Minimum online commitment requirement (MW) is the minimum total online commitment required for interval t for the defined set of resources able to participate in the satisfying the constraint. This quantity may differ by interval (by hour in DAM) with the amount of load within designated local areas. This formulation recognizes that the variation of required commitment versus the local load may not be linear.

Multiple constraint equations can be defined to incorporate different groups of resources depending on the procedure or outage that is being represented. A resource may participate in more than one minimum online commitment requirement constraint equation. The shadow prices of these constraints are not incorporated directly into any pricing calculations. The expectation is that adding these constraint equations will commit an appropriate set of resources that satisfies the minimum amount of commitment online required in the market processes to satisfy the operating procedural and outage requirements. If the constraint cannot be satisfied, the constraint will be violated at some configurable penalty value in the market optimization that is set to avoid under-procurement when resources are indeed available.

In addition to operating procedures, use of this functionality may also be considered for equipment outages that have a commitment requirement to return the system to normal steady state limits following contingencies or a commitment requirement to provide the necessary voltage and/or other system support.

For users who have access to Protected Data under Tariff section 6.5.10.1, the CAISO posts the MOC definitions used in the Day Ahead Market prior to the Day Ahead Market bidding deadline if possible, with the requirements posted three days afterwards. See the *Business Practice Manual for Market Instruments* for more information. Ongoing MOC enforcements are usually identified with the associated four digit procedure number, for example "ANYWHERE 7000". MOC enforcements related to equipment outages are usually identified with the associated outage number, for example "MOC ANYWHERE 22345678". In cases where an equipment outage MOC affects a large number of generating resources or where the duration is for an extended period, and the MOC requirement is known in advance, the CAISO may post a Market Notice as a courtesy to market participants. The CAISO will post a Market Notice for any new procedure-related MOC prior to the first day of enforcement.

Refer to the EDAM BPM for details on EDAM MOC activation details.

6.6.2.5 Enforcement of Constraints on the Interties

The CAISO enforces both scheduled and physical flows on the Interties through the use of a two-constraint approach. In the IFM, the ISO will continue to enforce a scheduling constraint and will include a physical flow constraint (based on the FNM expansion initiatives), each of which will consider both physical and Virtual Bids. To ensure uniqueness of prices intertie constraints, similar to other transmission constraints, are formulated with additional slack variables. The scheduling constraint will continue to be based on the assessment of Intertie Bids submitted by the Scheduling Coordinators relative to the Available Transfer Capability of the specific Intertie location. This will ensure that contract paths are honored and will be used for E-Tagging intertie schedules. The physical flow constraint will be based on the modeled flows for the Intertie, taking into account the actual power flow contributions from all resource schedules in the Full Network Model against the Available Transfer Capability of the Intertie. Unlike the scheduling constraint, the contributions of intertie schedules towards the physical flow limit will be based on the shift factors calculated from the network model, which reflects the amount of flow contribution that change in output will impose on an identified transmission facility or flowgate. Each Intertie will have a single Total Transfer Capability and the scheduling limit and physical flow limit will be compared against the Intertie's capacity. The scheduling limit and physical flow limit are not necessarily equal to each other.

In the Residual Unit Commitment, the CAISO will enforce two constraints that only consider physical awards with respect to contract path limits

(*i.e.*, Virtual Awards cannot provide counterflow to physical awards).

6.6.3 Co-optimization of Energy, ~~&~~ Ancillary Services, and Imbalance Reserves

The SCs submit AS Bids and Imbalance Reserve Bids in the DAM, and the IFM considers ~~AS Bids~~these bids in conjunction with Energy Bids to make AS Awards and Imbalance Reserve Awards. This is based on a simultaneous optimization that minimizes the total Bid Cost of clearing Congestion, balancing physical Energy and Virtual Supply and Demand, and reserving unloaded capacity to provide AS and Imbalance Reserves. ~~.~~

The optimization process can substitute higher-quality AS products for lower quality AS products. For example, it may reserve additional Spinning Reserves to cover part or all of the Non-Spinning Reserve requirements. Imbalance Reserves do not participate in this cascading hierarchy and are procured independently based on their specific requirements.

For purposes of the Day-Ahead AS procurement, all RA resources certified to provide Ancillary Services are deemed available to CAISO.

An important feature of the integration of AS and Imbalance Reserves with Energy and Congestion Management in the IFM is the ability of the IFM to optimally utilize import/export transmission capacity to import Energy, ~~and~~ AS, and Imbalance Reserves. ~~Import of Regulation Down utilizes export transmission capacity.~~ The IFM utilizes ~~import transmission~~this capacity for the most economically efficient combination of Energy and AS.

Like AS, ~~and~~ Imbalance Reserves awards do~~es~~ not create net counterflow against energy schedules ~~use of transmission capacity.~~in the base case optimization. However, to ensure awards are deliverable, the IFM includes Imbalance Reserve deployment scenarios. In these scenarios, IRU and IRD awards are modeled as energy injections and withdrawals, respectively, where they do compete with energy for transmission capacity and can provide counter-flow to constraints. The market co-optimizes the base case and these deployment scenarios simultaneously to produce a single, feasible set of awards.

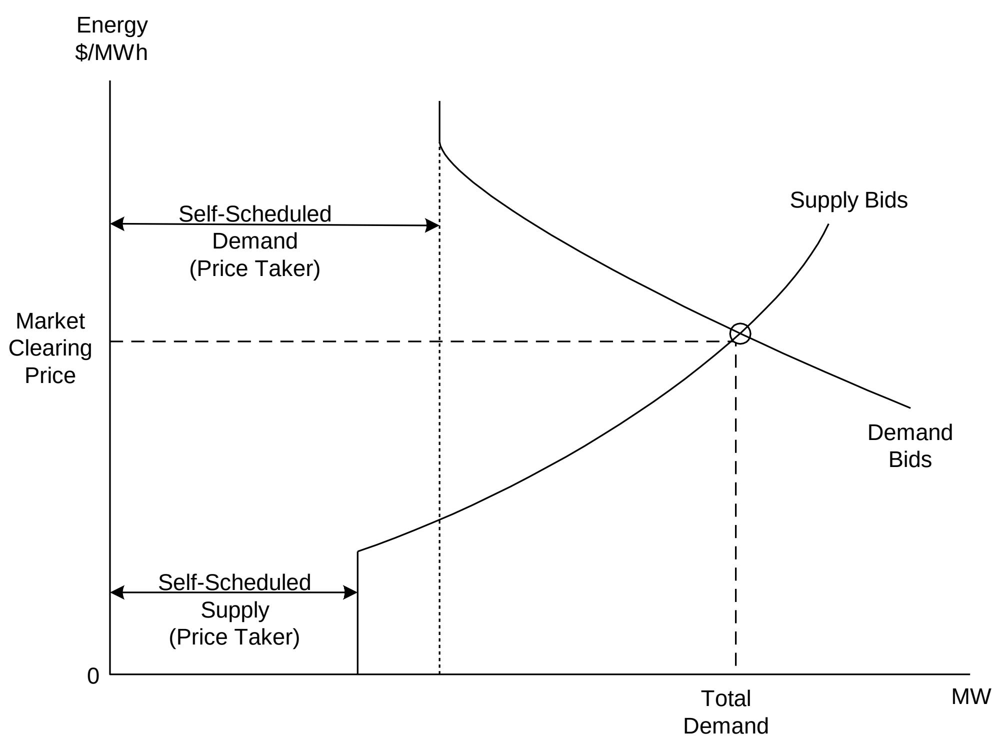
6.6.4 Market Clearing

Exhibit 6-3 illustrates the Market Clearing Price for Energy resulting from IFM, with the simplifying assumption that there are no Marginal Losses and that there is no Congestion. Under this scenario all the LMPs have the same value in $/MWh as the Market Clearing Price.

The Supply curve (actually steps) represents the "merit order" of the Generating Unit Bids from lowest to highest $/MWh, starting at the total Self-Scheduled Supply MW. The Demand curve (actually steps) represents the Demand Bids from highest to lowest $/MWh, starting at the total Self-Scheduled Demand MW. The intersection of these two curves is defined as the Market Clearing Price (MCP) for the total demand scheduled.

All scheduled Generating Units are paid the MCP and all scheduled Loads are charged the MCP.

Exhibit 6-3: Day-Ahead Market Clearing Price for Energy – Ignoring Marginal Losses & Congestion



In the general case where Transmission Losses and Congestion are present, the market clearing is a more complicated process that yields different LMPs at each network node.

6.6.5 Adjustment of Non-Priced Quantities in IFM

This section is based on CAISO Tariff Section 31.4, Uneconomic Adjustments in the IFM.

All Self-Schedules are respected by SCUC to the maximum extent possible and are protected from curtailment in the Congestion Management process to the extent that there are Economic Bids that can relieve Congestion. If all Effective Economic Bids in the IFM are exhausted, resource Self-Schedules between the resource's Minimum Load and the first Energy level of the first Energy Bid point is subject to adjustments based on the scheduling priorities listed in Section 6.6.5.3.

Through this process, imports and exports may be reduced to zero, Demand Schedules may be reduced to zero, and Price Taker Demand (LAP Load) may be reduced. However, prior to reducing Load the following process is used to ensure that LAP Load is not reduced unnecessarily.

Market Parameter Values

This section provides the specific value settings for a set of ISO market parameters that are used for adjusting non-priced quantities in the market optimizations.

The parameter values are organized into three sections by market process: the Integrated Forward Market (IFM), the Residual Unit Commitment (RUC), and the Real Time Market (RTM). The parameters in these tables are also known in the jargon of mathematical optimization as "penalty factors," which are associated with constraints on the optimization and which govern the conditions under which constraints may be relaxed and the setting of market prices when any constraints are relaxed. Importantly, the magnitude of the penalty factor values in the tables for each market reflect the hierarchical priority order in which the associated constraint may be relaxed in that market by the market software.

Integrated Forward Market (IFM) Parameter Values

Penalty Price Description	Scheduling Run Value[11] Based on $1000 Cap	Pricing Run Value Based on $1000 Cap	Scheduling Run Value Based on $2000 Cap	Pricing Run Value Based on $2000 Cap	Comment
Market energy	6500	1000	9800	2000	Market energy balance is the

[11] Penalty values are negatively valued for supply reduction and positively valued for demand reduction.

Penalty Price Description	Scheduling Run Value[11] Based on $1000 Cap	Pricing Run Value Based on $1000 Cap	Scheduling Run Value Based on $2000 Cap	Pricing Run Value Based on $2000 Cap	Comment
balance					requirement that total supply equal the sum of total demand plus losses for the entire system. In the IFM energy balance reflects the clearing of bid-in supply and demand; in the MPM component of the DAM it reflects the scheduling of bid-in supply against the ISO demand forecast.
Transmission constraints: Intertie scheduling	5000	1000	10000	2000	Intertie scheduling constraints limit the total amount of energy and ancillary service capacity that can be scheduled at each scheduling point.
Gas-burn nomogram	5000	1000	10000	2000	In the scheduling run, the market optimization enforces gas-burn constraints up to a point where the cost of enforcement (the "shadow price" of the constraint) reaches the parameter value, at which point the constraint is relaxed.
Legacy Reliability Must-Run (LRMR) pre-dispatch curtailment (supply)	-6000	-150	-12000	-150	The ISO considers transmission constraints when determining LRMR scheduling requirements. After the ISO has determined the LRMR scheduling requirements, the market optimization ensures that the designated capacity is scheduled in the market.
Pseudo-tie layoff energy	-4000	-150	-8000	-150	Pseudo-tie layoff energy is scheduled under contractual arrangements with the Balancing Authority in whose area a pseudo-tie generator is located.
Transmission constraints: branch, corridor, nomogram (base case and contingency analysis)	5000	1000	10000	2000	In the scheduling run, the market optimization enforces transmission constraints up to a point where the cost of enforcement (the "shadow price" of the constraint) reaches the parameter value, at which point the constraint is relaxed.
Generation Nomogram	5000	1000	10000	2000	In the scheduling run, the market optimization enforces generation constraints up to a point where the cost of enforcement (the "shadow

Penalty Price Description	Scheduling Run Value[11] Based on $1000 Cap	Pricing Run Value Based on $1000 Cap	Scheduling Run Value Based on $2000 Cap	Pricing Run Value Based on $2000 Cap	Comment
					price" of the constraint) reaches the parameter value, at which point the constraint is relaxed.
Transmission constraints: Transformer	5000	1000	10000	2000	In the scheduling run, the market optimization enforces transmission constraints up to a point where the cost of enforcement (the "shadow price" of the constraint) reaches the parameter value, at which point the constraint is relaxed.
Extremely Long Commitment	3750	1000	7500	2000	When a resource is committed through the extra-long commitment (ELC) process, or if a second or third day commitment occurs in the RUC process, that commitment is protect with a priority.
Load Serving Generator	-1800	-150	-3600	-150	Load Serving Generator for supply receive higher priority than Economic Bids at the bid floor.
RA Capacity	0	0	0	0	Priority for RA submitted into RUC
Transmission Ownership Right (TOR) self-schedule	5900, -5900	1000, -150	11800, -11800	2000 or -150	A TOR Self-Schedule will be honored in the market scheduling in preference to enforcing transmission constraints.
Existing Transmission Contract (ETC) self-schedule	5100 to 5900, -5100 to -5900	1000, -150	10200 to 11800, 10200 to 11800	2000, -150	An ETC Self-Schedule will be honored in the market scheduling in preference to enforcing transmission constraints. The typical value is set at $5500, but different values from $5100 to $5900 are possible if the instructions to the ISO establish differential priorities among ETC rights. For some ETC rights the ISO may use values below the stated scheduling run range if that is required for consistency with the instructions provided to the ISO by the PTO.
Converted Right (CVR) self-schedule	5500, -5500	1000, -150	11000, -11000	2000 or -150	A CVR Self-Schedule is assigned the same priority as the typical value for ETC Self-Schedules.
Ancillary Service Region	2500	250	5000	250	In the event of bid insufficiency, AS minimum requirements will be met

Penalty Price Description	Scheduling Run Value[11] Based on $1000 Cap	Pricing Run Value Based on $1000 Cap	Scheduling Run Value Based on $2000 Cap	Pricing Run Value Based on $2000 Cap	Comment
Regulation-up and Regulation-down Minimum Requirements					in preference to serving generic Self-Scheduled demand, but not at the cost of overloading transmission into AS regions.
Ancillary Service Region Spin Minimum Requirements	2250	250	4500	249	Spinning reserve minimum requirement is enforced with priority lower than regulation up minimum requirement in scheduling run.
Ancillary Service Region Non-Spin Minimum Requirements	2000	248	4000	248	Non-spin reserve minimum requirement is enforced with priority lower than spin minimum requirement in scheduling run.
Ancillary Service Region Maximum Limit on Upward Services	1500	250	3000	250	In the event of multiple AS regional requirements having bid insufficiency, it is undesirable to have multiple constraints produce AS prices equaling multiples of the AS bid cap. An alternative way to enforce sub-regional AS requirements is to enforce a maximum AS requirement on other AS regions, thereby reducing the AS prices in the other regions without causing excessive AS prices in the sub-region with bid insufficiency.
Energy Limit for daily constraint quantities	1500	250	3000	500	Energy limitation constraint used for total daily minimum or maximum limitation for quantities
Regulation Mileage UP and down minimum requirement	1000	1000	2000	2000	In the event of mileage bid insufficiency, mileage minimum requirements will be relaxed in preference to serving generic Self-Scheduled demand, but not at the cost of overloading transmission into AS regions.
Convergence bid nodal group constraints	750	750	1500	1500	Nodal group constraints used for DC to AC power flows convergence
Minimum Online Capacity (MOC) constraint	0	0	0	0	Minimum online capacity for reliability constraints
Self-scheduled	1800	1000	3600	2000	Pursuant to section 31.4, the

Penalty Price Description	Scheduling Run Value[11] Based on $1000 Cap	Pricing Run Value Based on $1000 Cap	Scheduling Run Value Based on $2000 Cap	Pricing Run Value Based on $2000 Cap	Comment
CAISO demand and self-scheduled exports using identified non-RA capacity. Export leg of wheel through self-schedules					uneconomic bid price for self-scheduled demand in the scheduling run exceeds the uneconomic bid price for self-scheduled supply and self-scheduled exports not using identified non-RA capacity.
Self-scheduled exports not using identified non-RA capacity, Exports leg of a low priority wheel through self-schedule	1050	1000	2100	2000	The scheduling parameter for self-scheduled exports not using identified non-RA capacity is set below the parameter for generic self-schedules for demand.
Regulatory Must-Run and Must Take supply curtailment	-1350	-150	-2700	-150	Regulatory must-run and must-take supply receive priority over generic self-schedules for supply resources.
Import price-taker self-schedule. Import leg of a high priority wheel through self-schedule	-1100	-150	-2200	-150	Generic self-schedules for supply receive higher priority than Economic Bids at the bid floor.
Import leg of a low priority wheel through self-schedule	0	0	0	0	Import side of a low priority wheel self-schedule
Conditionally qualified Regulation Up or Down self-provision	-405	NA	-810	NA	Conversion of AS self-schedules to Energy pursuant to section 31.3.1.3 received higher priority to maintaining the availability of regulation, over spinning and non-spinning reserve.
Conditionally qualified Spin self-provision	-400	NA	-800	NA	Conversion of AS self-schedules to Energy pursuant to section 31.3.1.3 receives higher priority to maintaining the availability of

Penalty Price Description	Scheduling Run Value[11] Based on $1000 Cap	Pricing Run Value Based on $1000 Cap	Scheduling Run Value Based on $2000 Cap	Pricing Run Value Based on $2000 Cap	Comment
					spinning reserve, over non-spinning reserve.
Conditionally qualified Non-Spin self-provision	-395	NA	-790	NA	This penalty price for conversion of self-provided non-spinning reserves balances the maintenance of AS self-schedules with ensuring that the conversion to energy occurs before transmission constraints are relaxed.
Conditionally unqualified Reg Up or Down self-provision	-195	NA	-390	NA	In instances where AS self-provision is not qualified pursuant to the MRTU tariff, the capacity can still be considered as an AS bid, along with regular AS bids. The price used for considering unqualified AS self-provision is lower than the AS bid cap, to allow it to be considered as an Economic Bid.
Conditionally unqualified Spin self-provision	-170	NA	-340	NA	Same as above.
Conditionally unqualified Non-Spin self-provision	-155	NA	-310	NA	Same as above.
Master Aggregated Capability Constraint	7300	1000	14600	2000	Penalty price for master or standalone ACC. Market optimization will not relax the point of interconnection limits.
Subordinate Aggregate Capability Constraints	1500	1000	3000	2000	Penalty price for sub-ACC.
Imbalance Reserve Up/Imbalance Reserve Down	55	55	55	55	Price cap for Imbalance Reserve

Residual Unit Commitment (RUC) Parameter Values

Penalty Price Description	Scheduling Run Value	Pricing Run Value	Comment
Transmission constraints: Intertie scheduling	3200	250	The Intertie scheduling constraint retains higher relative priority than other RUC constraints.
Market energy balance - under procurement. IFM cleared self-scheduled exports using identified non-RA capacity. IFM cleared export leg of a wheel through self-schedule	1600	250	The RUC procurement may be less than the Demand forecast if the CAISO has committed all available generation and accepted intertie bids up to the intertie capacity.
IFM cleared self-scheduled exports not using identified non-RA capacity	1350	250	Export priority higher for self-scheduled exports that cleared IFM than economic bids at $1000.
Transmission constraints: branch, corridor, nomogram (base case and contingency analysis)	1250	250	These constraints affect the final dispatch in the Real-Time Market, when conditions may differ from Day-Ahead.
Gas-burn nomogram	1250	250	In the scheduling run, the market optimization enforces gas-burn constraints up to a point where the cost of enforcement (the “shadow price” of the constraint) reaches the parameter value, at which point the constraint is relaxed.
Maximum energy limit in RUC schedule	1500	250	Limits the extent to which RUC can procure energy rather than unloaded capacity to meet the RUC target. For MRTU launch the limit will be set so that the total energy scheduled in the IFM and RUC will be no greater than 99% of the RUC target unless this limit is relaxed in the RUC scheduling run.
Limit on quick-start capacity scheduled in RUC	250	0	Limits the amount of quick-start capacity (resources that can be started up and on-line within 5 hours) that can be scheduled in RUC. For MRTU launch the limit will be set to 75%.
IFM cleared supply schedules	Min(energy bid price - $250, or $0)	0	These values preserve schedules established in IFM in both the RUC scheduling run and pricing run.
Market energy balance -over procurement	200	0	Market energy balance when the RUC procurement may be more than the Demand forecast.
Price-taker IFM cleared	-1350	0	IFM cleared price-taker supply bids and

Penalty Price Description	Scheduling Run Value	Pricing Run Value	Comment
supply self-schedules. IFM cleared import leg of a wheel through self-schedule			IFM cleared import leg of a wheel through self-schedule
IFM cleared economical exports	IFM bid-in price +300	0	Export adder priority for IFM schedules
Self-Scheduled import wheel that cleared in IFMIFM cleared import leg of a low priority wheel through self-schedule.	0	0	Import self-schedule that cleared in IFM which is the IFM penalty price and the RUC adder
RA capacity	0	0	Priority for RA submitted into RUC

Real Time Market Parameters

Penalty Price Description	Scheduling Run Value Based on $1000 Cap	Pricing Run Value Based on $1000 Cap	Scheduling Run Value Based on $2000 Cap	Pricing Run Value Based on $2000 Cap	Comment
Energy balance/Load curtailment, RUC cleared self-scheduled export using identified non-RA capacity. RUC cleared export leg of a wheel through self-schedule. Real-time market self-scheduled export using identified non-RA capacity. Real-time export leg of a wheel through self-schedule.	1450	1000	2900	2000	Scheduling run penalty price is set high to achieve high priority in serving forecast load and exports that utilize non-RA capacity. Energy bid cap as pricing run parameter reflects energy supply shortage.
Transmission constraints: Intertie	2900	1000	5800	2000	The highest among all constraints in scheduling run, penalty price reflects its priority over load serving. Energy bid cap as pricing

Penalty Price Description	Scheduling Run Value Based on $1000 Cap	Pricing Run Value Based on $1000 Cap	Scheduling Run Value Based on $2000 Cap	Pricing Run Value Based on $2000 Cap	Comment
scheduling					run parameter reflects energy supply shortage.
Gas-burn nomogram	1500	1000	3000	2000	Scheduling run penalty price will enforce gas-burn constraints up to a re-dispatch cost of $1500 per MWh. Energy bid cap as pricing run parameter consistent with the value for energy balance relaxation under a global energy supply shortage
Legacy Reliability Must-Run (LRMR) pre-dispatch curtailment (supply), and Exceptional Dispatch Supply	-6000	-150	-12000	-150	LRMR scheduling requirement is protected with higher priority over enforcement of internal transmission constraint in scheduling run. Energy bid floor is used as the pricing run parameter for any type of energy self-schedule.
Pseudo-tie layoff energy	-1500	-150	-3000	-150	Energy bid floor is used as the pricing run parameter for any type of energy self-schedule.
Transmission constraints: branch, corridor, nomogram (base case and contingency analysis)	1500	1000	3000	2000	Scheduling run penalty price will enforce internal transmission constraints up to a re-dispatch cost of $ of congestion relief in $1500 per MWh. Energy bid cap as pricing run parameter consistent with the value for energy balance relaxation under a global energy supply shortage.
Real Time TOR Supply Self Schedule	-5900	-150	-11800	-150	In RTM, TOR self-schedule scheduling run penalty price is much higher in magnitude than generic self-schedule but lower than transmission constraint. Energy bid floor is used as the pricing run parameter as any type of energy self-schedule.
Real Time ETC Supply Self Schedule	-5100 to -5900	-150	10200 to - 11800	-150	In RTM the range of penalty prices for different ETCs supply self-schedules are much higher in magnitude than generic supply self-schedules but lower than TOR. Energy bid floor is the pricing

Penalty Price Description	Scheduling Run Value Based on $1000 Cap	Pricing Run Value Based on $1000 Cap	Scheduling Run Value Based on $2000 Cap	Pricing Run Value Based on $2000 Cap	Comment
					parameter for all energy supply self-schedules.
Ancillary Service Region Reg-Up and Reg-Down Minimum Requirements	1450	250	2900	250	Scheduling run penalty price is below the one for transmission constraint. Pricing run parameter is set to the AS market bid cap to reflect AS supply shortage.
Ancillary Service Region Spin Minimum Requirements	1400	249	2800	249	Scheduling run penalty price is lower than the one for regulation-up minimum requirement. Pricing run parameter is set to the AS market bid cap to reflect AS supply shortage.
Ancillary Service Region Non-Spin Minimum Requirements	1350	248	2700	248	Scheduling run penalty price is lower than the one for spin minimum requirement. Pricing parameter is set to the AS market bid cap to reflect AS supply shortage.
Ancillary Service Region Maximum Limit on Upward Services	1200	248	2400	248	Scheduling run penalty price is lower than those for minimum requirements to avoid otherwise system-wide shortage by allowing sub-regional relaxation of the maximum requirement. AS market bid cap as pricing run to reflect the otherwise system-wide shortage.
RUC cleared self-scheduled exports not using identified non-RA capacity	1250	1000	2500	2000	RUC cleared scheduling run penalty price reflects relatively low priority in protection as compared to other demand categories. Energy bid cap as pricing run parameter to reflect energy supply shortage.
Self-scheduled exports not using identified non-RA capacity	1150	1000	2300	2000	Scheduling run penalty price reflects relatively low priority in protection as compared to other demand categories. Energy bid cap as pricing run parameter to reflect energy supply shortage.
Regulatory Must-Run and Must Take supply curtailment	-1400	-150	-2800	-150	Scheduling run penalty price reflects the higher priority of regulatory must-run and must-take supply received over generic self-schedules for supply resources.

Penalty Price Description	Scheduling Run Value Based on $1000 Cap	Pricing Run Value Based on $1000 Cap	Scheduling Run Value Based on $2000 Cap	Pricing Run Value Based on $2000 Cap	Comment
					Energy bid floor is the pricing parameter for all energy supply self-schedules.
Real-time market price taker supply self-schedule	-400	-150	-800	-150	Generic self-schedules for internal supply receive higher priority than Economic Bids at the bid floor.
Qualified Load Following self-provision Up or Down	-8500	0	-17000	0	Scheduling run penalty price reflects the highest priority among all categories of AS self-provision. AS bid floor is used as the pricing parameter for any type of AS self-provision.
Day ahead conditionally qualified Reg Up or Down Award	-7750	0	-15500	0	Scheduling run penalty price is higher than the penalty price for energy balance constraint to reflect higher in priority over energy. AS bid floor is pricing parameter for any type of AS self-provision.
Day ahead conditionally qualified Spin Award	-7700	0	-15400	0	Scheduling run penalty price is lower than the one for Reg-up. AS bid floor is pricing parameter for any type of AS self-provision.
Day ahead conditionally qualified Non-spin Award	-7650	0	-15300	0	Scheduling run penalty price is lower than the one for Spin. AS bid floor is pricing parameter for any type of AS self-provision.
Conditionally qualified Reg Up or Down Real Time self-provision (RTUC only)	-405	0	-810	0	Scheduling run penalty price allows the conversion of AS self-schedules to Energy to prevent LMP of local area from rising so high as to trigger transmission constraint relaxation. AS bid floor is pricing parameter for any type of AS self-provision.
Conditionally qualified Real Time Spin self-provision (RTUC only)	-400	0	-800	0	Scheduling run penalty price is below the one for regulating-up. AS bid floor is pricing parameter for any type of AS self-provision.
Conditionally qualified Real Time Non-Spin self-provision	-395	0	-790	0	Scheduling run penalty price is below the one for spin. AS bid floor is pricing parameter for any type of AS self-provision.

Penalty Price Description	Scheduling Run Value Based on $1000 Cap	Pricing Run Value Based on $1000 Cap	Scheduling Run Value Based on $2000 Cap	Pricing Run Value Based on $2000 Cap	Comment
(RTUC only)					
Conditionally unqualified Reg Up or Down Real Time self-provision (RTUC only)	-195	0	-390	0	In scheduling run, AS self-provision not qualified in pre-processing can still be considered as an AS bid with higher priority in the Energy/AS co-optimization along with regular AS bids. AS bid floor is pricing parameter for any type of AS self-provision.
Conditionally unqualified Spin Real Time self-provision (RTUC only)	-170	0	-340	0	Same as above.
Conditionally unqualified Non-Spin Real Time self-provision (RTUC only)	-155	0	-310	0	Same as above.
System power balance constraint	1100, -155	1000, -155	2200, -155	2000, -155	To reflect the role regulation plays in balancing the system for undersupply conditions when economic bids are exhausted, the ISO allows the system power balance constraint to relax by as much as the seasonal regulation requirement. For over-supply conditions, when economic bids are exhausted, the ISO allows the system power balance constraint to relax to about 10% of the seasonal regulation requirement. The prices are selected to allow for coordinated dispatch of bids that may exist at or near the bid cap, or at or near the bid floor.
Power Balance constraint for individual. WEIM areas	1100, -750	1000, -150	2200, -750	2000, -150	Subject to the FERC order granting waiver of tariff sections 27.4.3.2.and 27.4.3.4, and consistent with Section 10.1.6 of the BPM for Energy Imbalance Market, which implement the price discovery mechanism overriding the pricing parameters and yielding the last economic signal under

Penalty Price Description	Scheduling Run Value Based on $1000 Cap	Pricing Run Value Based on $1000 Cap	Scheduling Run Value Based on $2000 Cap	Pricing Run Value Based on $2000 Cap	Comment
					constraint relaxation. The scheduling run parameter is set to -750 for the individual WEIM areas to coordinate the relaxation of the WEIM power balance constraint during over-generation conditions relative to congestion on non-EIM constraints.
EIM Upward Available Balancing Capacity Range	1200 through 1050	Bid in Prices Range for WEIM Participating resource and DEB for WEIM Non-Participating	2400 through 2100	Bid in Prices Range for WEIM Participating resource and DEB for WEIM Non-Participating	The Penalty Price Range used for the Available Capacity Range prices to maintain the economic merit order reflected in the energy bid prices of the allocated energy bid portions
EIM Downward Available Balancing Capacity	-250 through -350	Bid in Prices Range for WEIM Participating resource and DEB for WEIM Non-Participating	-500 through -700	Bid in Prices Range for WEIM Participating resource and DEB for WEIM Non-Participating	The Penalty Price Range used for the Available Capacity Range prices to maintain the economic merit order reflected in the energy bid prices of the allocated energy bid portions
EIM Transfer Constraint	2900	1000	5800	2000	Penalty price and pricing parameter consistent with the transmission constraint;
Administrative Flexible Ramp Down Price Floor	-75	-75	-75	-75	Downward Demand Curve Price Cap
Administrative Flexible Ramp Up Price Ceiling	247	247	247	247	Upward Demand Curve Price Cap
EIM Incremental Flow and WEIM Area total Flow	1500	0	3000	0	Penalty price and pricing parameter consistent with the WEIM Entitlement Rate of Change constraint;
HASP AS resource protection of energy bid range	8000	1000	16000	2000	Penalty price used for protection of AS range on energy bid curve for HASP AS resources

Penalty Price Description	Scheduling Run Value Based on $1000 Cap	Pricing Run Value Based on $1000 Cap	Scheduling Run Value Based on $2000 Cap	Pricing Run Value Based on $2000 Cap	Comment
Exceptional Dispatch	5800	1000	11600	2000	Priority to exceptional dispatches made by operators
Load Serving Generator	1800	1000	3600	2000	Load Serving Generator for supply receive higher priority than Economic Bids at the bid floor.
Exceptional Dispatch for Tie Generators	2100	1000	4200	2000	Priority to exceptional dispatches made by operators for Tie generators
EIM Base scheduled exports	2000	1000	4000	2000	EIM base scheduling priority for export when tagged schedules do not exist
Tagged Quantity for exports	2000	1000	4000	2000	After clearing in the real time market, Inter-tie tagged priority for exports. Higher priority than load in real time.
EIM Base scheduled imports	-1250	-150	-4000	-150	EIM base scheduling priority for import when tagged schedules do not exist
Tagged Quantity for imports	-1250	-150	-4000	-150	After clearing in the real time market, Inter-tie tagged priority for imports. Higher priority than over-generation energy slack
Real-time price-taker self-schedule import with RUC schedule and import leg of high priority wheel through self-schedule with RUC schedule	-1200	-150	-2400	-150	For hourly bids in HASP and fifteen- minute bids in FMM, a RUC scheduled import self-schedule Has a higher priority than over-generation energy slack
Real-time price-taker self-schedule import without RUC schedule and import leg of high priority wheel through self-schedule without RUC schedule	-1100	-150	-2200	-150	For hourly bids in HASP and fifteen-minute bid in FMM, a real time submitted self-schedule with no RUC schedule has a higher priority than over-generation energy slack
Import leg of a wheel with no	0.0001	0	0.0002	0	Import side of a low priority wheel

Penalty Price Description	Scheduling Run Value Based on $1000 Cap	Pricing Run Value Based on $1000 Cap	Scheduling Run Value Based on $2000 Cap	Pricing Run Value Based on $2000 Cap	Comment
RUC schedule					self-schedule
Contingent operating reserves release for energy	1000	1000	2000	2000	Operator released contingent operating reserves can only be dispatched at the pricing Cap
Hourly Proxy Demand resource	1000	1000	2000	2000	Protection for hourly awarded proxy demand resource in markets after HASP
MSS load following instructions	360	360	720	720	For meter sub systems (MSS) load following instruction with in the designated load following capacity
MSS load following down capacity	-8000	-150	-16000	-150	For meter sub systems (MSS) load following down capacity reservation
MSS load following up capacity	8000	1000	16000	2000	For meter sub systems (MSS) load following down capacity reservation
Master Aggregated Capability Constraint	7300	1000	14600	2000	Penalty price for master or standalone ACC. Market optimization will not relax the point of interconnection limits.
Subordinate Aggregate Capability Constraints	1400	1000	2800	2000	Penalty price for sub-ACC.

Minimum Effectiveness Threshold

A lower limit on the effectiveness of resources considered for re-dispatch to relieve a congested transmission constraint is necessary to prevent the market software from accepting significant quantities of ineffective low-priced energy bids to achieve a small amount of congestion relief on the constraint. The ISO uses a value of two-tenths of a percent (0.2%) as the minimum effectiveness threshold for congestion management in the day-ahead and real-time markets. The minimum effectiveness threshold is used in the market power mitigation process for dynamic competitive path assesment and LMP decomposition purposes as well as for congestion management purposes.

Weigthing factor for quadratic slack variables

A weigthing factor associated with quadratic slack variables in the cost minimization problem are also needed for the formulation of the constraints that have an impact on energy prices, such as transmission constraints, to attain conditions for uniqueness of prices. This weigthing factor needs to be sufficiently small to preserve the price signal in conditions where the market needs to rely on constraint relaxations. The CAISO uses a value of 0.0001 as the weigthing factor for the quadratic slack variables in both the day-ahead and real-time markets.

6.6.5.1 Reduction of Self-Scheduled LAP Demand

This section is based on CAISO Tariff Section 31.3.1.2, Reduction of LAP Demand.

In the IFM, to the extent the CAISO Market software cannot resolve a non-competitive transmission constraint utilizing Effective Economic Bids such that Self-Scheduled Load at the LAP level would otherwise be reduced to relieve the constraint, CAISO Market software will adjust Non-priced Quantities in accordance with the process and criteria described in Section 24.7.3 of the CAISO Tariff. For this purpose the priority sequence, starting with the first type of Non-priced Quantity to be adjusted will be:

- (a) Schedule the Energy from Conditionally Qualified Self-Provided Ancillary Service Bids from capacity that is obligated to offer an Energy Bid under a must-offer obligation. C Consistent with Section 8.6.2 of the CAISO Tariff, the CAISO Market software could also utilize the Energy from Self-Provided Ancillary Service Bids from capacity that is not under a must-offer obligation to the extent the Scheduling Coordinator has submitted an Energy Bid for such capacity. Because the Conditionally Qualified Self-Provided Ancillary Services is included in the optimization, this step is automatic. The associated Energy Bid prices will be those resulting from the MPM process.

- (b) Relax the Constraint consistent with Section 27.4.3.1 of the CAISO Tariff, and establish prices consistent with Section 27.4.3.2 of the CAISO Tariff. No Constraints on Interties with adjacent Balancing Authority Areas will be relaxed in this procedure.

6.6.5.2 Reduction in Generation

Generation may be also reduced to a lower operating (or regulating) limit (or lower regulating limit plus any qualified Regulation Down AS Award or Ancillary Services self-provision, if applicable). Any schedules below the Minimum Load level are treated as fixed schedules and are not subject to adjustments for Congestion Management.

6.6.5.3 Scheduling Priorities

This section is based on CAISO Tariff Section 31.4, Adjustments of Non-priced Quantities in the IFM.

The scheduling priorities for the IFM from highest priority (last to be adjusted) to lowest priority (first to be adjusted) are as follows:

- Legacy Reliability Must Run (LRMR) pre-dispatch reduction
- Day-Ahead TOR (balanced Demand and Supply reduction)
- Day-Ahead ETCs (balanced Demand and Supply reduction); Different ETC priority levels are observed based upon global ETC priorities provided to CAISO by the Responsible PTOs
- Other self scheduled Load reduction subject to Section 31.3.1.2 of the CAISO Tariff, as described in Section 6.6.4.1 of this BPM.
- Day-Ahead Ahead Regulatory Must Run and Regulatory Must Take reduction Self-Scheduled Supply
- Other self scheduled Supply reduction
- Economic Demand and Supply Bids

6.6.5.4 Power Balance relaxation

The power balance constraint ensures that the sum of generation and imports equals the sum of demand, including exports and transmission losses. The shadow price of the power balance constraint establishes the system marginal energy cost, which the market uses to determine locational marginal prices. This constraint is set to the maximum energy bid price (the “soft” bid cap of $1,000/MWh under most circumstances) in the pricing run. This allows for bids to clear up to the soft bid cap. The power balance constraint needs to be at least as high as the highest submitted energy bid price. Otherwise, the optimization will relax the constraint rather than clear bids priced above its value. The CAISO market utilizes both a scheduling and pricing run to produce awards (dispatches) and prices. In the scheduling run, the market optimizes all submitted bids and clears awards based on the most effective economic solution. In the event a solution cannot be achieved, the market will adjust non-priced parameters (i.e., uneconomic adjustments) or relax constraints to attain a solution. The awards and resulting prices of this solution are passed to the pricing run. The pricing run information of the potential uneconomic adjustments and/or constraint relaxation is retained because after solving the scheduling run, the amounts of the adjustments and relaxations are known. These instances are modeled in the pricing run with slack variables with a small range beyond the solution of the scheduling run in order to have room in the optimization of the pricing run to find a solution and produce binding prices. In the event uneconomic adjustments are made or constraints are relaxed, the relevant penalty prices are applied.

The power balance penalty price in the market's pricing run remains at $1,000/MWh under routine conditions and all other market constraint penalty prices will remain scaled to $1,000/MWh. The power balance penalty price increases to a $2,000/MWh pricing run price (the "hard" bid cap), and the rest of the market constraint penalty prices are scaled relative to $2,000/MWh, under specific conditions described below. Consequently, this assumes that under normal market conditions the shortage price signal sent by the power balance constraint relaxation price should be based on the $1,000/MWh soft energy bid cap. The market utilizes two sets of pricing parameters:

1. Pricing parameters will be scaled to a $1,000/MWh power balance penalty price when both of the following conditions exist in any interval of the market horizon:
    a. Resource-specific resources have not submitted a cost-verified energy bid greater than $1,000/MWh.
    b. The CAISO-calculated maximum allowable import bid price is not greater than $1,000/MWh.
2. Pricing parameters will be scaled to a $2,000/MWh power balance penalty price when either of the following conditions exists in any interval of the market horizon:
    a. A Resource-specific resource has submitted a cost-verified energy bid greater than $1,000/MWh.
    b. The CAISO-calculated maximum allowable import bid price is greater than $1,000/MWh.

If the conditions are satisfied to set the pricing parameter for the power balance constraint to $2,000/MWh and the market must relax the power balance constraint, the market would set energy prices in the pricing run based on the amount of infeasibility from the scheduling run. The amount of infeasibility in the scheduling run will be compared to a small threshold value. If the infeasibility is less than the threshold value, the market would set prices based on the price of the highest priced cleared bid. If the infeasibility is more than the threshold value, prices will be set based on the $2,000/MWh power balance penalty price. The threshold value is intended to account for small supply shortfalls for which it is not appropriate to send the strong shortage pricing signal that setting prices based on $2,000/MWh would. These small apparent shortfalls may not actually represent actual shortfalls because of forecast and modeling inaccuracies. In addition, in balancing authority areas other than the CAISO in the EIM, they may not represent actual shortfalls because of other resources these balancing authority areas have that are not in the market.

The threshold value for each balancing authority area in the WEIM is based on the NERC BAL-001-2 Requirement R2. The requirement aims to maintain reliability by controlling interconnection frequency within defined limits. This is accomplished by ensuring Balancing Authority Area Control Error (ACE) is kept between predefined limits (BAAL). These BAAL limits (BAALLow and BAALHigh) are defined individually for each balancing authority area. The CAISO will utilize the BAALLow limit to define the threshold value for each balancing authority area in the EIM. This value can be used to represent the amount of supply that can be less than load while still maintaining system frequency within acceptable reliability criteria. Frequency is related to the balance of supply and load. System frequency is maintained by matching supply to demand. However, small mismatches and resulting differences in frequency from the desired 60 Hz are acceptable.

The $BAAL_{Low}$ limit, as defined by NERC is the following:

$$BAAL_{Low} = \left(-10B_i \times (FTL_{Low} - F_s)\right) \times \frac{(FTL_{Low} - F_s)}{(F_A - F_s)}$$

Where:

- $BAAL_{Low}$ is the Low Balancing Authority ACE Limit (MW)
- 10 is a constant to convert the Frequency Bias Setting from MW/0.1 Hz to MW/Hz
- B_i is the Frequency Bias Setting for a Balancing Authority (expressed as MW/0.1 Hz)
- F_A is the measured frequency in Hz.
- F_s is the scheduled frequency in Hz.
- FTL_{Low} is the Low Frequency Trigger Limit (calculated as F_s - 3ε1I Hz)
- Where ε1I is the constant derived from a targeted frequency bound for each Interconnection.
    - Western Interconnection ε1I = 0.0228 Hz

For establishing the threshold value, the Western Interconnection is balanced and the scheduled frequency is 60 Hz. Therefore, the CAISO will not apply the following term from the $BAAL_{Low}$ limit equation in the calculation of the threshold values: $\frac{(FTL_{Low} - F_s)}{(F_A - F_s)}$. This part of the equation modifies the frequency limits based on actual frequency in real-time. Consequently, it is not possible to incorporate this part of the equation to calculate set threshold limits in advance. It would not be practical to use limits that change for pricing purposes.

Consequently, the CAISO will calculate the threshold value for each WEIM balancing authority area and the CAISO using the first term of the $BAAL_{Low}$ limit as follows:

$$Threshold = \left(-10B_i \times (FTL_{Low} - F_s)\right).$$

Table 1 lists the applicable frequency bias setting values and the corresponding calculated threshold values for each participating WEIM balancing authority area and the CAISO based on 2020 information.

Table 1 Frequency Bias Settings and Calculated Threshold Values

Balancing Authority Area	2020 Frequency Bias Setting (MW/0.1 Hz)[12]	CAISO Calculated Threshold Values (MW)
AZPS	-99.1	67.8
BANC – total	-28.4	19.4
BCHA	-112.9	77.2
CAISO	-341.7	233.7
IPCO	-37.7	25.8
NEVP	-63.0	43.1
PACE	-89.9	61.5
PACW	-46.1	31.5
PGE	-39.5	27.0
PSEI	-35.1	24.0
SCL	-39.0	26.7
SRP	-56.7	38.8

The CAISO real-time market includes individual power balance constraints for each WEIM balancing authority area and an overall power balance constraint for the market. The overall power balance constraint for the market applies to the CAISO balancing authority area as well. The CAISO will set all of these power balance constraints at $2,000/MWh, and scale the other market constraints accordingly, when the conditions are met to set the power balance penalty price to $2,000/MWh.

Additionally, it is important to note that if the conditions are met to set the power balance penalty price to $2,000/MWh for any hour in the day-ahead market, the $2,000/MWh power balance penalty price will apply for all trading hours of the day-ahead market and real-time market for the same trading day. If the conditions are not met to set the power balance penalty price to $2,000/MWh in the day-ahead market, but the conditions apply to set the power balance penalty price to $2,000/MWh in the real-time market, the real-time market will use the $2,000/MWh power balance penalty price for all intervals of overlapping real-time market horizons. If the conditions to set the power balance penalty price to $2,000/MWh in all intervals of a real-time market horizon are not met, a $1,000/MWh power balance penalty price will be used in all intervals of that real-time market horizon. This is irrespective of the fact that a $2,000/MWh power balance penalty price may have been used for one or more of these intervals in a previous real-time market run. This approach is necessary so the market functions consistently across all intervals in its horizon.

The threshold value is not applied in the day-ahead market due to the differences in the way the market clears in DA VS real time. Additionally, since the NERC BAL-001-2 Requirement R2 is a real-time operating standard, it does not make sense to apply the threshold value based on this standard to the day-ahead market.

Example A:

The following example illustrates how penalty prices will remain set to the $1,000/MWh power balance penalty price when the highest-priced submitted bid from a resource-specific resource is less than $1,000/MWh and the CAISO-calculated maximum allowable import bid price is less than $1,000/MWh.

Assume the following market inputs in the real-time market:

- Highest-priced bid from a resource-specific resource = $900/MWh
- CAISO-calculated maximum allowable import bid price = $200/MWh
- CAISO threshold value = 233.7 MW

Given the conditions listed above, in the power balance penalty price would be set to $1,000/MWh to determine the dispatch and prices.

Assume the market must relax the power balance constraint. Energy prices would be set based on the $1,000/MWh power balance penalty price.

Example B:

The following example illustrates how penalty prices will be set to the $2,000/MWh power balance penalty price when the highest-priced submitted bid from a resource-specific resource is greater than $1,000/MWh. This example also outlines how energy prices are determined in the pricing run based on the amount of infeasibility.

Assume the following market inputs in the real-time market:

- Highest-priced, cost-verified bid from a resource-specific resource = $1,200/MWh
- CAISO-calculated maximum allowable import bid price = $700/MWh
- CAISO threshold value = 233.7 MW

The power balance penalty price would be set to $2,000/MWh to determine the dispatch because there is a submitted and cost-verified energy bid from a resource-specific resource greater than $1,000/MWh.

Assume the market must relax the power balance constraint and the highest-priced cleared economic bid is $1,200/MWh. Energy prices in the pricing run would be set based on the following:

- If the scheduling run infeasibility ≤ 233.7 MW, energy prices in the pricing run will be based on the $1,200/MWh highest-priced cleared economic bid.
- If the scheduling run infeasibility > 233.7 MW, energy prices in the pricing run will be based on the $2,000/MWh power balance penalty price.

Example C:

The following example illustrates how penalty prices will be set to the $2,000/MWh power balance penalty price when the CAISO-calculated maximum allowable import bid price is greater than $1,000/MWh. This example also outlines how energy prices are determined in the pricing run based on the amount of infeasibility when there is no resource-specific bid greater than $1,000/MWh.

Assume the following market inputs in the real-time market:

- Highest-priced bid from a resource-specific resource = $900/MWh
- CAISO-calculated maximum allowable import bid price = $1,100/MWh
- CAISO threshold value = 233.7 MW

The power balance penalty price would be set to $2,000/MWh to determine the dispatch because the CAISO-calculated maximum allowable import bid price is $1,100/MWh, which is greater than $1,000/MWh.

Assume the market must relax the power balance constraint and the highest-priced submitted bid from a resource-specific resource is $900/MWh. Energy prices in the pricing run would be set based on the following:

- If the scheduling run infeasibility ≤ 233.7 MW, energy prices in the pricing run will be based on the $1,000/MWh because there is no resource-specific bid greater than $1,000/MWh.
- If the scheduling run infeasibility > 233.7 MW, energy prices in the pricing run will be based on the $2,000/MWh power balance penalty price.

Example D:

The following example illustrates how penalty prices will be set to the $2,000/MWh power balance penalty price when the CAISO-calculated maximum allowable import bid price is greater than $1,000/MWh. This example also outlines how a submitted resource-adequacy import bid will be reduced to the CAISO-calculated maximum allowable import bid price. Further, this example highlights how energy prices are determined in the pricing run based on the amount of infeasibility.

Assume the following market inputs in the real-time market:

- Highest-priced bid from a resource-specific resource = $900/MWh
- Highest-priced resource adequacy import bid = $1,200/MWh
- CAISO-calculated maximum allowable import bid price = $1,100/MWh
- CAISO threshold value = 233.7 MW

The power balance penalty price would be set to $2,000/MWh to determine the dispatch because the CAISO-calculated maximum allowable import bid price is $1,100/MWh, which is greater than $1,000/MWh. The market reduces the submitted $1,200/MWh resource adequacy import bid to the $1,100/MWh maximum allowable import bid price.

Assume the market must relax the power balance constraint and the highest-priced cleared economic bid is the $1,100/MWh import bid. Energy prices in the pricing run would be set based on the following:

- If the scheduling run infeasibility ≤ 233.7 MW, energy prices in the pricing run will be based on the $1,100/MWh highest-priced cleared economic bid.
- If the scheduling run infeasibility > 233.7 MW, energy prices in the pricing run will be based on the $2,000/MWh power balance penalty price.

Example E:

The following example illustrates how penalty prices will be set to the $2,000/MWh power balance penalty price when the highest-priced, cost-verified submitted bid from a resource-specific resource is greater than $1,000/MWh. This example also outlines how energy prices are determined in based on the amount of infeasibility for an WEIM balancing authority area when it is import constrained and the market must relax the power balance constraint for that specific WEIM balancing authority area.

Assume the following market inputs in the real-time market:

- Highest-priced, cost-verified bid from a resource-specific resource within an WEIM balancing authority area = $1,200/MWh
  - This WEIM balancing authority area is import constrained.
- CAISO-calculated maximum allowable import bid price = $900/MWh
- EIM balancing authority area's threshold value = 25 MW
- EIM balancing authority area's available balancing capacity supply = 20 MW @ $100/MWh

Given the conditions listed above, the power balance penalty price would be set to $2,000/MWh to determine the dispatch because there is a submitted and cost-verified energy bid from a resource-specific resource greater than $1,000/MWh. This applies to all individual balancing authority area power balance constraints in the WEIM area and the market power balance constraint for the WEIM area as a whole.

Assume the market must relax the power balance constraint in the import constrained WEIM balancing authority area. The highest-priced cleared economic bid within the balancing authority is the $1,200/MWh bid. Energy prices in the pricing run would be set based on the following:

- If the scheduling run infeasibility ≤ 45 MW, energy prices in the pricing run will be based on the $1,200/MWh highest-priced cleared economic bid.

- If the scheduling run infeasibility > 45 MW, energy prices in the pricing run will be based on the $2,000/MWh power balance penalty price.

The scheduling run infeasibility is compared to the sum of the WEIM balancing authority area's threshold value and their available balancing capacity supply amount.

Since the market outside of this import constrained WEIM balancing authority area can reach a feasible solution, the overall system's power balance constraint does not need to be relaxed in this example, and prices outside the constrained balancing authority area are produced using its normal process.

The "available balancing capacity" feature currently implemented in the WEIM allows the market to recognize additional resources outside the market WEIM participants use to meet their balancing authority area responsibilities.[13] It includes bids for these resources in the market's bid stack, when the market must relax the power balance constraint for an WEIM balancing authority area. This allows the marginal economic bid to set the energy price within the balancing authority area and not the power balance penalty price.

In the event the market would otherwise relax the power balance constraint for a balancing authority area in the WEIM other than the CAISO, the available balancing capacity feature uses the capacity from the out-of-market available balancing capacity at penalty prices from $1,050/MWh to $1,200/MWh. This ensures that all available bids submitted up to the bid cap of $1,000/MWh are scheduled prior to releasing available balancing capacity into the bid stack. The pricing run then produces prices incorporating bids from the available balancing capacity resources.

Under this approach, the available balancing capacity will be released between $2,100/MWh and $2,400/MWh in the scheduling run when the $2,000/MWh set of pricing parameters is used in the market. This will ensure the priority level of available balancing capacity is maintained in the bid stack in the scheduling run.

6.6.6 IFM Outputs

The following IFM output information is produced and is financially and operationally binding:

- Optimal Unit Commitment status (on/off) over the Time Horizon
- Type of Unit Commitment status (self-commitment and CAISO-commitment)
- Optimal Energy Schedule for all resources over the Time Horizon

- Virtual Supply and Virtual Demand Awards
- Optimal AS Award for all resources over the Time Horizon
- Optimal Imbalance Reserve (IRU/IRD) Award for all eligible resources over the Time Horizon
- The total Energy, ~~and~~ AS, and Imbalance Reserve Bid Cost over the Time Horizon
- The Start-Up Cost ($) for each Generation resource or minimum curtailment payment ($) for each dispatchable Demand/Curtailable Demand resource during each CAISO-commitment period
- The Minimum Load Cost ($) for each Generation resource or minimum hourly payment ($) in each hour during each CAISO-commitment period
- The Start-Up Cost/Bid function ($, Minute) or minimum curtailment payment ($) used for each resource in each CAISO-Commitment Period.
- LMPs for each price Location including all resources; also LMP components (Energy, Marginal Loss, and Congestion components)
- RASMP for each AS Region
- ASMP for all resources providing Ancillary Services.
- Optimal Imbalance Reserve (IRU/IRD) Award for all eligible resources over the Time Horizon
- Resources at their effective minimum or maximum MW in each time interval
- The level of control and Constraint priority used in obtaining the solution. This informs the CAISO's operator as to how much of uneconomic Bid segments and/or Constraint violations were necessary to solve the optimization.
- Amount of any relaxed constraint violations, i.e., the extent to which any constraint was relaxed (in MW) in order to solve the optimization.

Both schedules and prices are derived from the pricing run of the IFM market to ensure consistency between schedules and prices. This consistency is important for prices that are financially binding to settle energy schedules.

6.6.7 Energy Settlement

Scheduling Coordinators on behalf of Generating Units, System Resources, and physical Supply Resources are paid for their Energy Schedule the LMP at their Location. Scheduling Coordinators on behalf of Non-Participating Load and export resources are charged for their Energy Schedule at the LMP at the corresponding LAP or Scheduling Point. Virtual Supply Awards are paid the Day-Ahead LMPs at their location and charged in Real-Time at the applicable FMM LMPs at the applicable PNodes or APNodes. Virtual Demand Awards are charged the Day-Ahead LMPs at their locations and paid in Real-Time at the applicable FMM LMPs at the applicable PNodes or APNodes. The LMP at an aggregate Location for an aggregate resource is an aggregate LMP. The net revenue from these payments and charges is attributed to Marginal Losses and Congestion and is allocated as described in the *BPM for Settlements & Billing*.

The Marginal Cost of Congestion (MCC) for the balanced portion of TOR and ETC Self-Schedules that clear the IFM is rebated to the designated SC for the relevant TOR or ETC. This rebate is calculated as the algebraic difference (it may be negative) between the MCC components at the financial sink and the financial source of the TOR or ETC, multiplied by the scheduled TOR or ETC MW. The financial source and sink of a TOR or ETC are registered Locations in the Master File and may be aggregate with associated distribution factors.

The financial source and the financial sink of a TOR or ETC may be different than the physical source and the physical sink of that TOR or ETC, but nonetheless, they are also registered Locations in the Master File and they may also be aggregate. The physical source and sink correspond to Supply and Demand resources, respectively, and are only used to provide scheduling priority to TOR and ETC Self-Schedules in the IFM. The physical source is also used to provide scheduling priority to TOR and ETC in the RTM if appropriate pursuant to the TRTC Instructions.

Inter-SC Trades of Energy are paid (for trade in) or charged (for trade out) the relevant Trading Hub, LAP, or Generating Resource LMP.

To ensure the deliverability of Imbalance Reserve awards, the IFM optimization includes deployment scenarios where these awards are modeled as energy flows. These hypothetical flows in the deployment scenarios can provide counter-flow on congested transmission paths, effectively displacing energy schedules that would otherwise have created congestion revenue in the base case. This can result in a shortfall between the congestion revenue collected from the energy settlement and the amount required to fully fund CRRs. To address this, the CAISO will calculate this "displaced congestion revenue" from the IRU/IRD flows in the deployment scenarios. This amount will be collected via the Imbalance Reserve cost allocation and used to ensure CRR holders are appropriately compensated.

Obligation CRRs from a source to a sink are paid the algebraic difference between the MCC components at the sink and the source. These payments are debited to the CRR Balancing Account.

CRR Options convey entitlement to Congestion revenues but not obligation to pay for counter flows. They allow the holder to avoid the obligation to pay when the Congestion component at the source is higher than the Congestion component at the sink. Thus, the CRR Option never has a negative value, but may have a positive value or a zero value. CAISO allocates CRR Options only to qualified entities that build new transmission facilities and do not receive a regulated rate of return – that is, merchant transmission developers who do not have a Transmission Revenue Requirement.

Finally, un-recovered Start-Up and Minimum Load Costs for non-self-committed resources are conditionally recovered through the Bid Cost Recovery mechanism. Moreover, unrecovered Energy and Ancillary Services Bid Costs for all resources are also recovered through the Bid Cost Recovery mechanism.

Details are given in the *BPM for Congestion Revenue Rights* and the *BPM for Settlements & Billing*.

6.6.8 Imbalance Reserve Product

Imbalance Reserve Product is a market-based product procured in the Day-Ahead Market to address operational challenges of maintaining power balance between the day-ahead and real-time horizons. The product is composed of Imbalance Reserve Up (IRU) and Imbalance Reserve Down (IRD) capacities. This product is procured in the Integrated Forward Market (IFM). The Imbalance Reserve Product is resource ramping capability that is reserved from the day-ahead energy schedule to address net load uncertainty and granularity differences that may materialize between the Day-Ahead and Real-Time Markets.

6.6.8.1 Imbalance Reserve Product Market Design

Imbalance Reserves are modeled as procurement requirements in the IFM co-optimization. Imbalance Reserve Up (IRU) and Imbalance Reserve Down (IRD) are procured to meet system-wide requirements.

To ensure the deliverability of awarded Imbalance Reserves, the IFM optimization includes deployment scenarios. In these scenarios, awarded IRU/IRD capacity is modeled as energy to test its deliverability against network constraints. The market produces a single, co-optimized solution that is feasible in the base case (for energy and ancillary services) and in the IRU/IRD deployment scenarios simultaneously.

The following are the features of the Imbalance Reserve Product;

- Suppliers submit separate, hourly price and quantity bids for Imbalance Reserve Up and Imbalance Reserve Down in the Day-Ahead Market.
- The product is procured in the IFM, co-optimized with energy and ancillary services.
- Resources must submit an economic energy bid for the capacity range that overlaps with their Imbalance Reserve bid.
- Eligible resources must be dispatchable in the Fifteen-Minute Market (FMM). The maximum award is based on a resource's 30-minute ramp capability. Offline resources may be eligible if they have a start-up time of 15 minutes or less.
- The market procures against an hourly system-wide requirement for IRU and IRD, which is determined based on historical forecast errors.
- An Imbalance Reserve Demand Curve is used to relax the procurement requirement at high prices, assessing the trade-off between the procurement cost and the operational value of the reserves.
- Resources receiving an Imbalance Reserve award have a must-offer obligation for that capacity in the Real-Time Market.
- IRU and IRD awards are financially binding and are paid the locational Imbalance Reserve Marginal Price (IRMP) for the respective product (IRUMP/IRDMP).

The CAISO calculates the IRU and IRD requirements for each hour of the Trading Day. This calculation is based on the historical uncertainty in the day-ahead load, solar, and wind forecasts.

- Historical data is used to identify the forecast error between the Day-Ahead Market and the Fifteen-Minute Market.
- Quantile regression is used to determine the requirement based on these historical errors and the prevailing forecasts for load, wind, and solar for the upcoming Trading Day. This statistical method estimates the requirement needed to cover a high percentile of expected forecast error (e.g., 97.5% for upward need and 2.5% for downward need).

6.7 Market Power Mitigation for RUC

The RUC market power mitigation (MPM-RUC) process is used to identify and mitigate potentially uncompetitive bids for Reliability Capacity Up (RCU). This process runs after the IFM and before the RUC to ensure that the prices for reliability capacity remain competitive. In the absence of sufficient resources to rely on competition, scheduling coordinators could potentially manipulate the RCU price in their local area by economically withholding supply. Any scheduling coordinator that is identified through this process will have their RCU bids subject to mitigation.

The MPM-RUC process will consist of a single market optimization run in which all modeled transmission constraints are enforced. It will utilize the same market optimization engine as used in the RUC. Some characteristics of RUC LMPM are summarized as follows:

- The MPM-RUC process occurs after the IFM is complete and before the final, binding RUC run.
- The Time Horizon for MPM-RUC is 24 hours.
- Each market interval for MPM-RUC is one hour.
- Reliability Capacity Down (RCD) bids are not subject to mitigation.
- RCU bids from non-EDAM intertie resources certified to provide reliability capacity are not subject to mitigation.

6.7.1 Decomposition method

The MPM-RUC method uses the same locational marginal price decomposition method as the IFM. After the market optimization, the marginal price for Reliability Capacity Up is decomposed into a competitive and non-competitive congestion component.

Under this method, a positive non-competitive congestion component indicates the potential for local market power. An RCU bid from a resource that can provide counter-flow to an uncompetitive constraint is subject to mitigation.

The reference bus selection for this process is the same as described in Section 6.5.1.

Every resource with a non-competitive congestion component greater than the Mitigation Threshold Price (currently set at zero) is subject to mitigation. RCU bids from any such resources will be mitigated downward to the higher of the resource's Default Availability Bid for reliability capacity or the competitive marginal price for RCU. The competitive marginal price for RCU is the marginal price of RCU at the resource's location minus the non-competitive congestion component thereof. A small configurable adder, which in all cases will be less than $0.01, is added to the competitive price.

6.7.2 Competitive Path Criteria

As part of the MPM-RUC run, an in-line dynamic competitive path assessment (DCPA) determines whether a binding transmission constraint is competitive or non-competitive. A Transmission Constraint is competitive by default unless it is determined to be non-competitive as part of this calculation.

This will occur when the maximum available supply of RCU counter-flow from all portfolios of suppliers that are not identified as potentially pivotal is less than the demand for RCU counter-flow needed to resolve the constraint.

If, for some reason, the DCPA is unable to function, the MPM-RUC will rely on a default competitive path list compiled based on historical analysis of congestion and previous DCPA results from past RUC runs.

The process for identifying gas-limited resources and deeming associated constraints non-competitive mirrors the process in Section 6.5.3, but the assessment is based on the availability of Reliability Capacity Up rather than energy.

6.7.3 Default Bids

The MPM-RUC process uses a Default Availability Bid for the mitigation of RCU bids. This default bid is distinct from the Default Energy Bid (DEB).

The Default Availability Bid is a static, system-wide value that serves as the mitigation "floor" for RCU bids. Initially, this value is set to be the same as the Default Availability Bid for Imbalance Reserve Up.

Please refer to the BPM for Market Instruments, Attachment D for more information on the specific value for Default Availability Bids.

~~6.7~~6.8 Residual Unit Commitment

As described above, the IFM clears the market based on the Self-Schedules and Economic Demand Bids of the SCs, and as a result it may clear at an overall level that is significantly lower than the CAISO Forecast of CAISO Demand for the next day. The purpose of the RUC process is to assess the resulting gap between the IFM Scheduled Load and the CAISO Forecast of CAISO Demand, and to ensure that sufficient physical reliability capacity is committed or otherwise ~~be~~ available for Dispatch in Real-Time in order to meet the Demand Forecast for each Trading Hour of the Trading Day. The process procures upward reliability capacity (RCU) when the forecast is greater than the physical supply cleared in the IFM, and procures downward reliability capacity (RCD) when the forecast is less than the physical supply cleared in the IFM.

To achieve this objective, the RUC process may commit and issue Start-Up Instructions to resources that are not committed at all in the IFM, as well as identify and procure additional ~~unloaded~~ reliability capacity (RCU/RCD) from resources that are committed and scheduled in the IFM. ~~and designate this capacity as needed for Real-Time Dispatch in particular Trading Hours of the Trading Day.~~

~~While RUC only procures capacity for the 24 hours of the next day, RUC's time horizon is configurable from 24 hours up to 168 hours, unlike the 24 hour time horizon in IFM. This longer time horizon allows RUC to consider capacity needs in beyond the first day, which enables RUC to procure capacity in a manner that may reduce unit cycling over the midnight hours. For example, if RUC needs additional capacity near the end of the trading day RUC may procure that capacity from a Long Start Unit if it foresees a need for that unit in the following day, and it would be more economic to keep the unit on-line than start it up the following day. In addition, the longer time horizon will allows the RUC process to consider the economic commitment of Extremely Long-Start Resources which have a startup time of greater than 18 hours and which generally cannot be considered in the normal IFM function. For these resources RUC may issue advisory start-up instructions for commitments which occur beyond the first 24 hours if the unit's start-up time would prevent the commitment to be feasible in a subsequent run. These advisory ELS commitment instructions are confirmed and made binding by the CAISO operators in the ELS commitment process. Within the RUC's time horizon, resource's commitment cost and bids will be considered in the entire corresponding time frame.~~The RUC process procures capacity for the 24-hour day-ahead time horizon.

~~The ability to look beyond the twenty-four hour time period may be deactivated in order to address system and processing requirements. In which case, RUC will not issue any advisory commitments to ELS Resources and all ELS resources are committed by the CAISO operator through its processes, as necessary.~~

To perform this function, the RUC utilizes the same SCUC optimization and FNM that the IFM uses, but instead of using Demand Bids, it distributes the CAISO Forecast of CAISO Demand (here after CFCD) over the CNodes of the FNM using the system Load Distribution Factors

(LDFs). It then treats all IFM resource (Generation, import and export) Schedules at a high scheduling priority so they are not re-optimized in RUC unless uneconomic adjustments are necessary. The RUC determines any incremental unit commitments and procures capacity from ~~RUC Availability~~Reliability Capacity Bids to meet the RUC procurement target. Capacity selected in this process is then expected to be bid in and be made available to the RTM.

In performing this optimization, RUC ignores submitted Energy Bids and uses ~~RUC Availability~~ Reliability Capacity Bids instead~~, with the provision that such Bids must be zero for all capacity that has been designated Resource Adequacy Capacity.~~. RUC also considers Start-Up and Minimum Load Costs for optimal commitment of units to meet the RUC procurement target for resources not committed in the IFM. A market power mitigation pass is performed before the RUC run to mitigate RCU bids where appropriate. Based on these Bids the RUC process calculates, in addition to the new Unit Commitment and dispatch process, ~~RUC prices at each PNode.~~locational marginal prices for RCU and RCD. The RUC process thus designates ~~RUC Capacity~~Reliability Capacity on a locational basis, in the sense that it identifies such capacity by determining a feasible Dispatch of that capacity to meet the RUC procurement target. The following summarizes the RUC processes described in this section:

- RUC Objective
- RUC Inputs
- RUC procurement target
- Distribution of CFCD on Full Network Model
- Day-Ahead Schedules for Supply
- ~~RUC Availability~~Reliability Capacity (RCU/RCD) Bids
- RUC Operational Constraints
- RUC Execution
- RUC Outputs

~~6.7.1~~6.8.1 RUC Objective

The objective of the RUC optimization is to minimize the incremental Start-Up, Minimum Load and incremental ~~RUC Availability Bids~~bids for Reliability Capacity (RCU/RCD) in order to ensure sufficient resources are committed and/or capacity is available to meet the adjusted CFCD for each hour over the next 24 hours~~ of the next Operating Day~~, where:

Incremental ~~availability~~ costs are represented by the ~~RUC Availability Bids~~bids for Reliability Capacity Up (RCU) and Reliability Capacity Down (RCD).~~ RUC Availability Bids associated with capacity from resources that are under a contractual obligation to offer capacity such as Resource Adequacy Capacity resources are $0/MWh. RUC Availability Payments are paid to capacity eligible to receive such payments, per hour~~

~~per MW of capacity identified in RUC above the greater of the resource's Day-Ahead Schedule, Day-Ahead LRMR Schedule, RUC RA obligation or a resource's Minimum Load~~. Resources receive payment for awarded reliability capacity at the relevant locational marginal price. ~~RUC Availability Bids are processed as follows:~~

- ~~For the first 24 hours of the optimization, RUC uses Availability Bids which are applicable for the Trade Date.~~

- ~~For the forward trading days beyond the first trade day, for non-extremely Long- Start resources, the CAISO will selects a date from the historic seven days, up to and including the Trade Date, based on which date most closely matches the period. Energy bids and energy self schedules will be selected from that date and applied to the second 24 hour period.~~

- ~~However, Energy Bids for ELS resources are copied from the Trade Date to the forward trade days, in order to preserve the bidding intention of the ELS resources.~~

- ~~For the first 24 hours of the optimization,~~ Day-Ahead Schedules and Ancillary Service and Imbalance Reserve Awards as a result of the IFM are maintained (fixed) in determining the incremental quantity of ~~RUC~~ Reliability Capacity necessary to meet the adjusted CFCD.

- ~~For the second and third 24 hours of the optimization, self-schedules from the selected dates are used as a proxy for the Day-Ahead schedules. Also for the second and third 24 hours, an adjustment is made to the CFCD to account for Ancillary Service awards that would have been made in the second and third 24 hour periods.~~

~~6.7.2~~6.8.2 RUC Inputs

This section identifies those inputs that are particularly specific to RUC. Inputs that are common to all the DAM functions are identified in earlier sections of this BPM.

~~6.7.2.1~~6.8.2.1 RUC Inputs Common to MPM/IFM

- System Load Distribution Factors, same as in MPM, (see Section 3.1.4, Load Distribution Factors)

- Generation Distribution Factors (see Section 3.1.2, Generation Distribution Factors)

- Transmission Constraints

- Generation Outages (see *BPM for Outage Management*)

- Daily total Energy Limits (applies to both Minimum Load and ~~RUC~~ Reliability Capacity Awards (RCU/RCD))

~~**6.7.2.2 Differences between first 24 hours and forward trade hours of the optimization**~~

~~RUC data inputs for the 72 hour time horizon come from the following sources:~~

- ~~Bids: As a proxy for the actual bids submitted for the Trade Date (first 24 hour period) bids, including RUC Availability Bids, Start-up Costs, and Minimum Load Costs, will be replicated from one of the last seven days, up to and including the Trade Date. The actual dates are chosen by the CAISO based on the closest match to the optimization period.~~

  ~~In order to preserve the bidding intention of Extremely Long-Start Resources, energy bids and self-schedules for the second and third 24 hour period for these resources will be replicated from the Trade Date. If this were not done, it would be possible that an Extremely Long-Start Resource would receive a binding commitment based on a bid from a prior day, when they did not submit a bid for the Trade Date.~~

- ~~Master File Data: Data including Pmin, Pmax, resource type, etc. will be replicated from the Trade Date to the forward hours. All resources will assume the MF definitions effective on the first trade day.~~

- ~~Forecasts: Forecast data, including load forecasts, outage forecasts, etc. will be based on the latest data available.~~

~~6.7.2.3~~6.8.2.2 RUC Zones

A RUC Zone is a designated area representing a collection of CNodes such as an IOU service area, UDC, MSS, Local Capacity Area. The CAISO may develop such collections of CNodes as sufficient historical CAISO Demand and relevant weather data becomes available to perform a Demand Forecast. RUC Zones are defined to allow CAISO Operators to adjust the CFCD on a local area basis as input to the RUC process, to ensure that the RUC process results in adequate local capacity procurement. The CFCD for a RUC Zone is produced by the CAISO's Demand Forecasting tools and is adjustable by CAISO Operators on a RUC zone basis.

The CAISO has defined the RUC Zones to be equivalent to the existing appropriate aggregation level of CAISO demand forecast systems. The mapping of RUC Zones to CNodes shall be static data, maintained in the CAISO Master File. The status of each RUC Zone shall remain active for as long as the CAISO's Automated Demand Forecast System (ALFS), or its successor, maintains such regional forecasting capabilities.

The CAISO will initially use three RUC Zones corresponding to three TAC areas. The number of RUC Zones may increase in the future in order to adjust the CFCD on a more granular basis. In the future, if the CAISO improves its demand forecasting capabilities to represent greater locational diversity, then the definitions of RUC Zones may be modified to reflect these changes. Such changes would be put before Market Participants for review and comment prior to implementation.

~~6.7.2.4~~6.8.2.3 CAISO Forecast of CAISO Demand (CFCD)

CFCD is determined by CAISO for each load forecast zone. A load forecast zone corresponds to defined areas representing UDC, MSS or Load serving boundary for which CAISO has sufficient historical CAISO Demand and relevant weather data to perform a Demand Forecast. The CFCD serves as the RUC procurement target; the difference between the CFCD and the physical supply schedules from the IFM determines the need for upward or downward reliability capacity.

CAISO forecasts CAISO Demand for each hour of the next seven Operating Days for each load forecast zone utilizing neural-network forecasting software that is widely used in the utility industry. To forecast the weather, CAISO utilizes multiple weather forecasting data sources so as to reduce forecasting errors. CAISO continually monitors its weather forecasting and Load forecasting results to ensure the average forecast error is minimized.

~~6.7.2.5~~6.8.2.4 RUC Procurement Target

The RUC procurement target is based on the difference between CFCD and the ~~IFM Scheduled Demand~~physical supply cleared in the IFM for each Trading Hour of the next Trading Day, and based on the CFCD for the following forward trade days. This determines the need to procure RCU if the forecast exceeds the cleared physical supply, or RCD if the cleared physical supply exceeds the forecast.

The CFCD for each RUC Zone is distributed nodally over the Full Network Model (FNM). For the RUC process, the Day-Ahead Schedules for Supply and Imbalance Reserve Awards resulting from the IFM ~~(Self-Schedules for the following forward trade days)~~ are modeled as ~~Self-Schedules~~fixed schedules with high scheduling priority so that RUC identifies the incremental ~~Supply~~ RCU or RCD needed to serve the difference between the ~~Day-Ahead Schedule for Supply of Energy~~physical supply and the adjusted CFCD.

Once the initial RUC procurement target is calculated for each RUC zone, adjustments to these quantities may be made, on a RUC zone basis, according to the provisions described in the following sections. An example of such adjustment is Demand Response where if a SC informs

CAISO about participation in Demand Response, CFCD is lowered accordingly which in effect reduces the RUC procurement target.

~~6.7.2.5.1~~6.8.2.4.1 RUC Zone Adjustment

In order to ensure sufficient capacity and resources are committed while at the same time reducing the possibility of over-procurement in RUC, CAISO may make the following adjustments to the hourly CFCD by RUC zone. After all the individual adjustments are determined as described below the CAISO adjusts the CFCD of each affected RUC zone, without making changes to the LDFs within that RUC Zone. The RUC Zone CFCD adjustment can be absolute or relative as follows:

$$CFCD_{RZ,hour,adj} = CFCD_{RZ,hour,orig} + \Delta CFCD_{RZ,hour,adj}$$

Or

$$CFCD_{RZ,hour,adj} = CFCD_{RZ,hour,orig} \times \%CFCD_{RZ,hour,adj} / 100$$

Where:

- $\Delta CFCD_{RZ,hour,adj}$: The total quantity of CFCD adjustments in MW is based on the summation of the adjustment for: 1) Metered Subsystems that have opted-out or are Load Following MSS, 2) negative adjustments for Demand Response, 3) positive adjustments to CFCD for Eligible Intermittent Resources, 4) positive Demand adjustments to CFCD for forecasted net reductions in Self-Scheduled Supply (forecast reductions in Self-Scheduled Generation and imports) expected to be submitted in the Real-Time Market, and 5) any other CAISO Operator input. Criteria 1 through 4 describe the primary conditions under which the CAISO may change RUC procurement. However, as Balancing Authority Area Operator, the CAISO reserves the flexibility to adjust RUC procurement to address unforeseen circumstances that could affect reliability.

- $CFCD_{RZ,hour,orig}$: The original CFCD.

- $CFCD_{RZ,hour,adj}$: The adjusted CFCD used as the input for the RUC.

- $\%CFCD_{RZ,hour,adj}$: The adjustment as a percentage of the original CFCD.

The adjustments associated with Eligible Intermittent Resources and forecasted Self-Schedules to be submitted in the Real-Time Market can result in either positive Demand side adjustments or positive Supply side adjustments. Positive Demand side adjustments are reflected as adjustment to the CFCD and positive Supply side adjustments are represented as an adjustment to the expected output of individual resources or imports. Refer to CAISO Tariff Section 31.5.3.

~~6.7.2.5.2~~6.8.2.4.2 MSS Adjustment

This section is based on CAISO Tariff Section 31.5.2, Metered Subsystem RUC Obligation.

~~MSS Operators are permitted to make an annual election to opt-in or opt-out of RUC participation. Prior to the deadline for the annual CRR Allocation and Auction process, as specified in Section 36 of the CAISO Tariff, an MSS Operator must notify CAISO of its RUC participation option for the following CRR cycle:~~

~~CAISO Tariff Section 31.5.2.1, MSS Operator Opts-In to RUC Procurement states that:~~

- ~~**Opt-in to RUC Procurement** – If the MSS Operator opts-in to the RUC procurement process,~~ All Metered Subsystems (MSS) are required to participate in the RUC procurement process. T~~t~~he SC for the MSS is treated like any other SC that Bids in the DAM with respect to RUC procurement by CAISO and allocation of RUC costs. CAISO considers the CAISO Demand Forecast of the MSS Demand in setting the RUC procurement target, and the SC for the MSS is responsible for any applicable allocation of costs related to the Bid Cost Recovery for RUC as provided in Section 11.8 of the CAISO Tariff.

CAISO Tariff Section 31.5.2.2, MSS Operator Opts-Out of RUC Procurement states that:

- **Opt-out of RUC Procurement** – If an MSS Operator opts-out of the RUC procurement process, CAISO does not consider the CAISO Demand Forecast of the MSS Demand in setting the RUC procurement target, and does not commit resources in RUC to serve the MSS Demand. The MSS Operator is responsible for meeting the Supply requirements for serving its Demand (i.e., "Load following") in accordance with this Section 31.5.2.2 of the CAISO Tariff, and it is exempt from the allocation of costs related to the Bid Cost Recovery for RUC as provided in Section 11.8 of the CAISO Tariff. The MSS that opts out of CAISO's RUC procurement has two options for meeting the Supply requirements for serving its Demand, which it can select on an hourly basis depending on how it Self-Schedules its Demand in the DAM. The two options are:
  - Based on CAISO Demand Forecast (see CAISO Tariff Section 31.5.2.2.1)
  - Not Based on CAISO Demand Forecast (see CAISO Tariff Section 31.5.2.2)

An MSS that has elected to opt-out of RUC, or has elected to Load follow and therefore has also elected to opt-out of RUC, is required to provide sufficient resources in the Day-Ahead

Market, and in the case of a Load following MSS, follow its Load within a tolerance band. To reflect these options CAISO replaces the CFCD for such an MSS with the quantity of Demand Self-Scheduled by the MSS in the IFM. By doing so, CAISO prevents RUC from committing additional capacity or resources for any differences between the CFCD for the MSS and the MSS Self-Scheduled quantities in the IFM. MSS adjustment is defined as follows:

$$CFCD_{MSS,Opt\text{-}out,RUC} = DS_{MSS\_Opt\text{-}out,IFM}$$

Where:

- $CFCD_{MSS,Opt\text{-}out,RUC}$: The CFCD used for the RUC zone for an MSS that either elected to opt out of RUC or has opted out as a result of electing to Load follow its MSS Demand.

- $DS_{MSS\_Opt\text{-}out,IFM}$: The quantity of scheduled CAISO Demand associated with an MSS that either elected to opt out of RUC or has opted out as a result of electing to Load follow its MSS Demand.

~~6.7.2.5.3~~6.8.2.4.3 Demand Response Adjustment

There are two different categories of Demand Response: 1) Demand Response that is triggered by a system emergency event and 2) Demand Response that is triggered by price or some other event that is known in advance. Only the Demand Response that is in category 2, that is certain of being curtailed, can be counted on as an adjustment to the RUC procurement target. If an SC informs CAISO prior to 1000 hours on the day prior to the Trading Day that Demand Response for the Trading Day can be exercised by CAISO, then the CFCD is reduced accordingly when running RUC. This communication may happen in the form of a data template (for e.g. .csv file) which includes SCID, Trade Date, Hour, RUC Zone and the available Demand Response for the applicable time period in MW.

~~6.7.2.5.4~~6.8.2.4.4 Eligible Intermittent Resource Adjustment

Eligible Intermittent Resources (EIRs) have the opportunity to bid or schedule in the Day-Ahead Market. Consequently, the ultimate quantity scheduled from EIRs may differ from the CAISO forecasted deliveries from the EIRs. CAISO may adjust the forecasted Demand either up or down for such differences by RUC zone for which the EIR resides. To the extent the scheduled quantity for an EIR in IFM is less than the quantity forecasted by CAISO, the CAISO makes a Supply side adjustment in RUC by using the CAISO forecasted quantity for the EIR as the expected delivered quantity. However, to the extent the scheduled quantity for an EIR in IFM is greater than the quantity forecasted by CAISO, CAISO makes a Demand side adjustment to the RUC zone Demand equal to the difference between the Day-Ahead Schedule and the CAISO forecasted quantity.

CAISO uses a neural-network forecasting service/software to forecast deliveries from EIRs based on the relevant forecasted weather parameters that affect the applicable EIR. CAISO monitors and tunes forecasting parameters on an ongoing basis to reduce intermittent forecasting error. EIR adjustment is defined as follows:

$$CFCD_{RZ,IRPAdj} = \max(0, \Sigma G_{RZ,IRP,IFM,Sch} - \Sigma G_{RZ,IRP,DAM,CAISOForecast})$$

Or

$$SA_{Gen,IRPAdj} = \max(0, \Sigma G_{RZ,IRP,DAM,CAISOForecast} - \Sigma G_{RZ,IRP,IFM,Sch})$$

Where:

- $CFCD_{RZ,IRPAdj}$: The quantity of adjusted CFCD by RUC zone as a result of differences in scheduled and forecasted quantities for EIR for Trading Hour.
- $SA_{Gen,IRPAdj}$: The quantity of Supply adjustment made to an intermittent resource when the Day-Ahead Schedule for the EIR is less than the CAISO forecast for delivery for the EIR.
- $\Sigma G_{RZ,IRP,IFM,Sch}$: The total quantity of scheduled EIR within RUC zone for a Trading Hour.
- $\Sigma G_{RZ,IRP,DAM,CAISOForecast}$: The total quantity of CAISO forecast EIR deliveries within RUC zone for a Trading Hour.

~~6.7.2.5.5~~6.8.2.4.5 Real-Time Expected Incremental Supply Self-Schedule Adjustment

In order to avoid over procurement of RUC, CAISO estimates the RTM Self-Schedules for resources that usually submit RTM Self-Schedules that are greater than their Day-Ahead Schedules. The estimation is performed using a similar-day approach.

The CAISO Operator can set the length of the Self-Schedule moving average window. Initially this moving average window is set by default to seven days; in which case the weekday estimate is based on the average of five most recent weekdays and the weekend estimate is based on the average of the two most recent weekend days. To the extent weather conditions differ significantly from the historical days, additional adjustment may be necessary, where the systematic approach does not yield Schedules consistent with expected weather or other system conditions. After determining the estimate of Real-Time Self-Schedules, CAISO adjusts the CFCD of a RUC zone based on the forecasted quantity changes in Supply as a result of Self-Schedules submitted in RTM. A similar day forecasting approach is used to forecast the Real-Time Self-Scheduled adjustment. This adjustment for forecasted Real-Time Self-Schedules could result in positive or negative adjustments.

- A **Demand** adjustment to CFCD occurs when there is a net forecast **decrease** in Real-Time Self-Schedule Supply relative to the Day-Ahead Schedule Supply.

- A **Supply** adjustment to the individual resources occurs when there is a net forecast **increase** in Real-Time Self-Schedule Supply relative to the Day-Ahead Schedule Supply of the individual resource

~~6.7.2.5.6~~6.8.2.4.6 Day-Ahead Ancillary Service Procurement Deficiency Adjustment

While CAISO intends to procure 100% of its forecasted Ancillary Service reserve requirement in the IFM based on the CFCD, CAISO reserves the ability to make adjustments to the CFCD used in RUC to ensure sufficient capacity is available or resources committed in cases that CAISO is unable to procure 100% of its forecasted reserve requirement in the IFM. While the CFCD used in RUC may be adjusted based on reserve procurement deficiencies, CAISO does not procure specific AS products in RUC, nor does the RUC optimization consider AS-related performance requirements of available capacity.

For example, it is not within RUC's objective to ensure that sufficient 10-minute service is available. However, to the extent RUC identifies capacity, such capacity is obligated to bid that capacity into the Real-Time Market as Energy and in so doing also allows CAISO to either dispatch Energy or acquire Operating Reserve from such capacity in the Real-Time Market to the extent such units qualify for the provision of such reserves.

~~6.7.2.5.7~~6.8.2.4.7 Operator Review & Adjustment

The CAISO Operator reviews the CFCD and all calculated adjustments. The CAISO Operator has the authority to accept, modify, or reject such adjustments. If the CAISO Operator determines it must modify or reject adjustments, the CAISO Operator logs sufficient information as to reason, Operating Hour, and specific modification(s) made to the calculated adjustments. Furthermore, such CAISO Operator adjustments are reviewed and approved by the CAISO Shift-Supervisor.

CAISO makes information regarding CAISO Operator adjustments available to Market Participants in a report. This information is described in more detail in the *BPM for Market Instruments, Sections 11 and 12.*

~~6.7.2.6~~6.8.2.5 Day-Ahead Schedules for Supply

~~Prior to determining the quantity of additional capacity that needs to be available, CAISO introduces and honors the resource commitments and associated Supply Schedules that have cleared the IFM. However, after potential RUC zone specific procurement target adjustments are factored into CFCD, the resulting distribution of Demand on individual CNodes for RUC may~~

~~be different from that used in the IFM. Because of this, RUC Capacity may be procured from resources in a RUC zone where the CFCD had been increased relative to the IFM scheduled Demand, even when the total system wide Day-Ahead Schedules are equal to or greater than the total system wide RUC CFCD. As a result of this, IFM resource Schedules entered into the RUC optimization as high priority Self-Schedules (essentially fixed resources) may need to be reduced. For some resources, this may result in a RUC Schedule that is lower than the Day-Ahead Schedule in order to satisfy the SCUC power balance constraint, which effectively means that the Day-Ahead Schedule of the resource was reduced to accommodate procurement of RUC Capacity from another resource. Note that this reduction of the Day-Ahead Schedule in RUC has no bearing on the settlement of the original Day-Ahead Schedule.~~The RUC process ensures there is sufficient physical resource capacity to meet the CAISO Demand Forecast. It addresses differences between the physical supply cleared in the IFM and the forecast, which can arise from virtual supply clearing in the IFM or from under-scheduling of load relative to the forecast. In this process, the RUC may procure Reliability Capacity Up (RCU) or Reliability Capacity Down (RCD). IFM resource schedules are treated as high-priority in the RUC optimization but may be adjusted (up or down) to ensure the physical power balance constraint is met against the CAISO forecast. For some resources, this may result in a RUC schedule that is different from their Day-Ahead Schedule. Note that any adjustment to a resource's schedule in RUC has no bearing on the settlement of its original Day-Ahead Schedule.

LRMR Generation Schedules that have been determined in the pre-IFM, MPM process are also honored in the RUC process. Therefore, if a resource is dispatched to 200 MW in the pre-IFM, MPM process, but only clears the IFM at 100 MW, the RMR resource is scheduled at 200 MW as input to RUC.

Constrained Output Generators (COG) are dispatched to their constrained output level in RUC. Therefore, a COG resource that has a PMin=PMax=50 MW may be dispatched in IFM at 20 MW. In RUC, however, such a COG resource schedule of 50 MW is enforced as input to the RUC process.

Intertie transactions with neighboring Balancing Authorities must be based on physical schedules. Since Virtual Supply and Virtual Demand are not considered in RUC, the RUC intertie results are used as a basis for energy schedules subject to check-out. Note that RUC attempts to honor the cleared IFM physical schedules like the Supply Schedules mentioned above. In the case of intertie schedules, Intertie constraints may bind in cases where the counter-flow effects of Virtual Bids are removed, thus the cleared physical Intertie results from RUC may not be the same as the results from IFM. The difference from the treatment of Supply Schedules is that the RUC result is operationally binding and becomes the basis for E-Tags that may be submitted in the Day Ahead timeframe. In other words, energy profiles on E-Tags submitted for IFM awards above cleared RUC schedules will not be approved.

Other supply, such as Existing Transmission Contracts (ETCs), Converted Rights (CVRs) or Transmission Ownership Rights (TORs) Self-Schedules are also honored at the Self-Scheduled levels established in the Day-Ahead Schedule through the IFM.

Wheeling transactions are not explicitly kept balanced in RUC because they are already protected by IFM self-schedule scheduling priority.

Forbidden Region constraint is not enforced in RUC because the RUC is procuring capacity not energy. This constraint is enforced in MPM/IFM.

Supply adjustments to Eligible Intermittent Resources and forecasted increased in RTM Self-Schedules may be made as described in Section 6.8.2.4.1~~6.7.2.5.1~~, RUC Zone Adjustment.

~~6.7.2.7~~6.8.2.6 ~~RUC Availability~~Reliability Capacity Bids

~~Participation in RUC is validated by the RUC eligibility designation contained in the Master File. Generating Units (except for certain exempt Use Limited Resources), Dynamic System Resources and Resource-Specific System Resources are designated as eligible for RUC. Non-Resource-Specific, non-Dynamic System Resources and RDRR resources are designated as NOT eligible for RUC. SCs may only submit RUC Availability Bids (above the Minimum Load) for which they show also submit an Energy Bid to participate in the IFM. Scheduling Coordinators may submit RUC Availability Bids on behalf of eligible capacity that is not subject to a RUC obligation. The CAISO will optimize all RA Capacity from Generating Units, Imports or System Resources at $0/MW per hour for the full amount of RA Capacity for a given resource. SCs may submit non-zero RUC Availability Bids for the portion of a resource's capacity that is not RA Capacity, unless the resource is subject to CAISO Tariff Appendix II, in which case the RUC Availability Bids must be $0/MWh for any capacity bid in.~~

~~A RUC Availability Bid is a ($/MW, MW) pair. The meaning of a RUC Availability Bid differs depending on whether the resource that submits the RUC Availability Bid has a Resource Adequacy obligation. If a resource does not have a RA obligation, the Scheduling Coordinator has the option of submitting a RUC Availability Bid pursuant to the rules in Section 30.5.2.7 of the CAISO tariff and Section 7.1 of the BPM for Market Instruments. If a resource has a RA obligation, a certain amount of capacity of this resource is registered with CAISO as RA Capacity. RA Capacity that is not a hydroelectric Generating Unit, Pumping Load or Non-Dispatchable Use-Limited Resource exempt from the RUC obligation pursuant to CAISO Tariff section 40.6.4.3.2, must also participate in both the IFM and the RUC processes. Moreover, the RA Capacity must participate in the RUC process with a $0/MW RUC Availability Bid for the~~

~~entire RA Capacity. This $0/MW RUC Availability Bid is generated by the CAISO on behalf of resources with a RUC obligation.~~

~~An SC need not submit a RUC Availability Bid for a Generating Unit or System Resource for the portion of the resource capacity that is under RUC obligation. For these resources that are obligated to offer their RA Capacity to RUC pursuant to Section 40.6 of the Tariff, RUC will automatically insert a RUC Availability Bid for the applicable RA Capacity and that bid will be equal to $0/MWh. In the event that a Generating Unit or System Resource only has part of its capacity designated as RA Capacity, the SC may only submit a RUC Availability Bid for any non-RA Capacity for that resource. The RUC Availability bid used in RUC will be constructed as follows: from the higher of the Minimum Load or the IFM Schedule up to the RA Capacity minus any Regulation Up/ Spin/ Non-Spin awards, a $0/MWh bid is created for any unused portion of the resource's RA Capacity. Any submitted RUC Availability Bid is then put on top at the submitted price. For Use-Limited Resources that are not exempt from the RUC obligation, the ISO will create a RUC Availability Bid consistent with the resources' RA capacity offered into the Day-Ahead Market through their Bids.~~

~~As stated in CAISO Tariff Section 40.6.4.3.2 "Hydro and Non-Dispatchable Use Limited Resources", Hydro resources and Non-Dispatchable Use-Limited Resources are required to submit Self-Schedule or Bids in the Day-Ahead Market for their expected available Energy or their expected as-available Energy, as applicable, in the Day-Ahead Market and RTM. Hydro resources and Non-Dispatchable Use-Limited Resources are not subject to commitment in the RUC process.~~

~~The RUC bidding requirements applicable to RA Capacity are described in more detail in the BPM for Reliability Requirements.~~

~~The total amount of RUC Capacity (which considers both the RA Capacity plus the submitted RUC Availability Bid quantity for an RA resource) is limited by the upper operating limit minus the sum of Day-Ahead Schedule and the upward Ancillary Service Awards. In other words, the sum of the DAM Energy Schedule, the upward Ancillary Service Awards including Ancillary self-provisions, and the RUC Award is limited by the upper operating limit.~~

~~If a resource subject to a Legacy RMR contract is determined to have a requirement for an hour in the Day-Ahead, and if any portion of the LRMR requirement has not been cleared in the IFM by the Scheduled Demand, the entire amount of requirement are represented as a LRMR Self-Schedule in the RUC to avoid over-committing other resources.~~

~~While IFM honors multi-hour Intertie Block Bids when procuring Energy, post IFM processes (RUC and RTM) are not designed to enforce multi-hour block constraints. Therefore, RUC~~

~~evaluates all intertie RUC Availability and RTM evaluates System Resource Energy Bids on an hourly basis instead of a multi-hour block basis.~~

~~Exhibit 6-4 defines the RUC Capacity that is available on a Generator that has been scheduled by the IFM. This Generator is also providing AS.~~

The RUC process is enhanced to procure both upward and downward dispatch capability through two new products: Reliability Capacity Up (RCU) and Reliability Capacity Down (RCD).

Participation in RUC is validated by the RCU/RCD eligibility designation contained in the Master File. Resources providing RA capacity that are required to participate in RUC must bid their RA capacity for RCU. Bids for RCD are optional. An energy bid is required for a resource to be eligible to offer RCU or RCD.

A Reliability Capacity bid is a ($/MW, MW) pair submitted for RCU or RCD. Resources providing RA capacity have a must-offer obligation for RCU. For any RA capacity not offered, the CAISO will insert a bid at the Default Availability Bid (DAB) price. Non-RA resources may bid into the RUC process optionally. RCU bids are subject to market power mitigation in a dedicated RUC-MPM pass.

Hydro resources and Non-Dispatchable Use-Limited Resources are required to submit Self-Schedule or Bids in the Day-Ahead Market for their expected available Energy, as applicable, in the Day-Ahead Market and RTM. Hydro resources and Non-Dispatchable Use-Limited Resources are not subject to commitment in the RUC process.

The total amount of Reliability Capacity procured is constrained by the resource's operational limits. The sum of the DAM Energy Schedule and the net Reliability Capacity award (RCU minus RCD) is limited by the upper and lower operating limits.

If a resource subject to a Legacy RMR contract is determined to have a requirement for an hour in the Day-Ahead, and if any portion of the LRMR requirement has not been cleared in the IFM by the Scheduled Demand, the entire amount of requirement is represented as a LRMR Self-Schedule in the RUC to avoid over-committing other resources.

Exhibit 6-3: Capacity Available for RUC

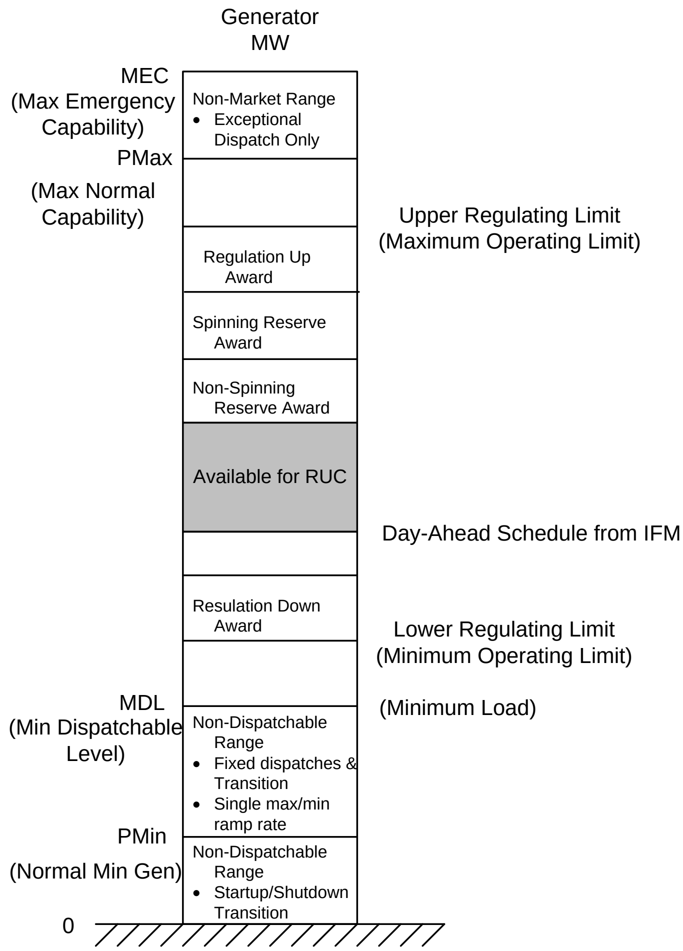


Exhibit 6-5 summarizes the characteristics of: Start-Up Costs, Minimum Load Costs as they apply in RUC, and the RUC Availability Bid for the various types of resources.

Exhibit 6-4: RUC Start Up, Minimum Load, & Availability Bid Eligibility

	Start-Up Costs	**Minimum Load Costs**	**RUC Availability Bid**
Participating Generator	Cost-Based Or Standing six-month Bid (CAISO Tariff: 30.4, 30.5.2.2)	Cost-Based Or Standing six-month Bid (CAISO Tariff: 30.4, 30.5.2.2)	~~RA Capacity = $0~~ Non RA Capacity is eligible to Bid (CAISO Tariff: 31.5.1.1, 31.5.1.2)
Constrained Output	Cost-Based	Cost-Based	No RUC Availability Bid

	Start-Up Costs	Minimum Load Costs	RUC Availability Bid
Generator (COG)	Or Standing six-month Bid (CAISO Tariff: 30.4, 30.5.2.2)	Or Standing six-month Bid (CAISO Tariff: 30.4, 30.5.2.2)	permissible; but accounted for in RUC based on Minimum Load cost bid (CAISO Tariff: 31.5.1.1)
Resource-Specific System Resource	Cost-Based Or Standing six-month Bid (CAISO Tariff: 30.4, 30.5.2.4)	Cost-Based Or Standing six-month Bid (CAISO Tariff: 30.4, 30.5.2.4)	~~RA Capacity = $0~~ Dynamic non-RA Capacity eligible to bid otherwise Other non-RA not eligible to bid into RUC (CAISO Tariff: 31.5.1.1)
Non-Resource-Specific System Resource	N/A (CAISO Tariff: 30.5.2.4)	N/A (CAISO Tariff: 30.5.2.4)	~~RA Capacity = $0~~ Dynamic non-RA Capacity eligible to bid otherwise Other non-RA not eligible to bid into RUC (CAISO Tariff: 31.5.1.1)
Participating Load (using Full Participating Load Model)	Not supported initially	Not supported initially	Not supported Initially
Participating (Pump) Load (using pumped-storage model)	N/A	N/A	N/A
Non-Participating Load	N/A	N/A	N/A

~~6.7.2.8~~6.8.2.7 RUC Operational Constraints

The RUC process has the ability to incorporate additional operational constraints using solution parameters that are set by a CAISO Operator. The following sections describe the criteria that are used for setting these constraint parameters. Although the CAISO Operator can set these constraint parameters, these parameters are not expected to change often after a period of initial implementation. After the initial implementation period, CAISO will post a notice to Market Participants when these parameters are to be changed.

~~6.7.2.8.1~~6.8.2.7.1 Capacity Constraints

The capacity constraints ensure that sufficient ~~RUC~~ Reliability Capacity is procured to meet the CFCD. This is accomplished by enforcing the Power balance between the total physical Supply (which includes IFM Energy Schedules, LRMR Generation Schedules that result from MPM , RCU, and RCD~~and RUC Capacity~~) and the total Demand (which includes IFM export Schedules and Demand Forecast.) The CFCD can be adjusted to increase the RUC target if there is AS Bid insufficiency in IFM, as described in Section 6.8.2.3~~6.7.2.4~~ above.

~~6.7.2.8.2~~6.8.2.7.2 Maximum Energy Constraint

In order to reduce the possibility that CAISO over-commits capacity in RUC when trying to meet the CFCD, RUC is capable of enforcing a constraint on the solution that would limit the total quantity of IFM Energy Schedules plus RUC Minimum Load Energy to be less than a percentage of the total CFCD.

$$\Sigma(\text{Pmin}) + \Sigma(\text{DA Imports}) - \Sigma(\text{DA Exports}) + \Sigma(\text{DA Gen}) <= \%E_{\text{RUC,Limiit}} \text{ x CFCD}$$

Where:

- Σ(PMin) : The total of all Minimum Load Energy committed in RUC for a Trading Hour
- Σ(DA Imports) : The total of DA Scheduled imports for a Trading Hour
- Σ (DA Exports) : The total of DA Scheduled exports for a Trading Hour
- Σ (DA Gen) : The total of DA Scheduled Generation Energy for a Trading Hour
- $\%E_{\text{RUC,Limiit}}$: The % Energy of CFCD Energy limitation.

This RUC Energy constraint is a soft-constraint and can be violated to obtain a solution. CAISO currently sets the RUC Energy Limit constraint to be between 95% and 100% of the CFCD.

Operational factors that are considered in setting this parameter are:

- Demand Forecast error
- Operational conditions such as Overgeneration
- Seasonal factors

~~6.7.2.8.3~~6.8.2.7.3 Short-Start Unit Capacity Constraint

This section is based on CAISO Tariff Section 31.5.4, RUC Procurement Constraints

In order to limit RUC from relying excessively on the capacity of Short-Start Units when making RUC decisions, CAISO may limit the percentage of total Short-Start Unit capacity that is committed in RUC. Short-Start Units are limited based on the following equation:

$$\Sigma(CAP_{RUC,QS}) <= \%SS \times \Sigma(CAP_{Total,QS})$$

Where:

- $\Sigma(CAP_{RUC,QS})$: The total capacity of Short-Start Unit capacity ~~committed in RUC~~awarded as RCU
- %SS : The percentage of total Short-Start Unit capacity parameter
- $\Sigma(CAP_{Total,QS})$: The total Short-Start Unit capacity available in the CAISO.

The Short-Start Unit capacity percentage limit is set to 100% by default. However, CAISO Operators may set this parameter as low as 75%. Operational factors that are considered in setting the Short-Start Unit constraint parameter are:

- Historical confidence that a Short-Start Unit actually starts when needed. Short-Start Unit performance is assessed based on operational experience among the CAISO's operators, collectively for all Short-Start resources.
- The need to conserve the number of run-hours and the number of start-ups per year for critical loading periods
- Seasonal constraints such as Overgeneration[14]

All of these factors work in the same direction to reduce the capacity percentage limit below the default value of 100%.

~~6.7.3~~6.8.3 RUC Execution

After completing the IFM and steps described above, CAISO executes the RUC process for the next Trading Day using the Security Constrained Unit Commitment (SCUC) algorithm. RUC simultaneously optimizes between 24 and 168 hours with the objective to minimize the total Start-Up Costs, Minimum Load Costs, and ~~incremental availability costs (i.e., RUC Availability Bid)~~ the bid costs of Reliability Capacity (RCU/RCD) while meeting the adjusted CFCD. Using the Full Network Model, RUC also ensures that transmission constraints are not violated.

The RUC process is run every day whether or not the Day-Ahead Schedule for Demand is greater than the CFCD. If no additional resource needs to be procured or no additional resources need to be committed, then RUC completes its execution without having to commit any additional resource capacity. However, it is possible that RUC needs to identify additional ~~RUC Capacity~~RCU or commit additional resources either because of insufficient ~~Load~~ physical supply being scheduled in the IFM (e.g., due to virtual awards) or due to transmission

[14] Over-generation tends to occur during off-peak hours, when the level of RUC procurement is low. This factor, therefore, should have only a small impact on Short Short-Start Unit procurement.

constraints because of differences in the Location and quantity of Demand scheduled in the IFM and the CFCD. Additionally, if the physical supply cleared in the IFM is greater than the CFCD, RUC may procure downward capacity (RCD).

While RUC commits resource capacity from Long-Start and Short-Start Units to meet CFCD, RUC does not automatically de-commit resources in cases of Overgeneration conditions or in cases where the Day-Ahead Schedules exceed the CFCD. The RUC solution identifies to the CAISO Operator resources that may need to be considered for de-commitment. The CAISO Operator reviews and assesses the results prior to making any manual de-commitment decisions. The RUC can also transition multi-stage generating resources to a lower configuration (but not shut down) to manage congestion and oversupply.

~~6.7.4~~6.8.4 RUC Outputs

This section summarizes the results of the RUC process. Unless otherwise noted, only results from the first 24 hours are considered binding and published.

~~6.7.4.1~~6.8.4.1 RUC Schedules

The total MW per hour amount of capacity committed by RUC including the MW per hour amounts committed in the Day-Ahead Schedule. RUC schedules are derived from the scheduling run to ensure schedules are physically feasible.

~~6.7.4.2~~ Reliability Capacity (RCU/RCD) and Awards~~RUC Capacity and RUC Awards~~

~~RUC Capacity and RUC Awards~~RCU and RCD Awards are determined as follows:

- ~~RUC Capacity~~Reliability Capacity Up (RCU) is the positive difference between the RUC Schedule and the ~~greater of the Day-Ahead Schedule or the Minimum Load of a resource.~~IFM schedule of a resource.
- Reliability Capacity Down (RCD) is the negative difference between the IFM Schedule and the RUC Schedule of a resource.
- The portion of the capacity that corresponds to the Minimum Load is not considered ~~RUC Capacity~~RCU and it is not eligible for ~~RUC~~ Reliability Capacity Bid Cost compensation since the Minimum Load Energy is compensated at the Minimum Load Cost in Bid Cost Recovery. For Extremely Long-Start Resources committed in the following forward trade days of the time horizon, only capacity up to Minimum Load will be committed.

- The portion of the ~~RUC~~ Reliability Capacity from a LRMR unit that is used in the RUC optimization to meet CFCD is not eligible for ~~RUC~~ an RCU or RCD Award since the capacity is already compensated through LRMR Contract.

- ~~The portion of the RUC Capacity that corresponds to RA RUC obligation is also not eligible for RUC Award.~~

- Any RUC Capacity in excess of LRMR Capacity ~~or RA RUC obligation~~ is considered a RUC Award eligible for RUC Payment.

CAISO only issues start-up instructions to Long-Start Units and Extremely Long-Start Resources that must be started sufficiently in advance of real time to meet Real-Time Demand. For Extremely Long-Start Resources, advisory start-up instructions may be issued for start times up to the end of the time horizon. However, these instructions will only be binding after confirmed by the CAISO operator and if the resource's startup time prevents it's re-evaluation in the following day's IFM/RUC run. For other units, the CAISO re-evaluates their commitment decisions in STUC and RTUC. However, the RUC Schedule determined by RUC is made available to the relevant SCs even if a RUC Start-Up instruction is not issued in the DAM.

~~6.7.4.3~~6.8.4.2 ~~RUC~~ Reliability Capacity Pricing

~~RUC Prices are calculated by the RUC optimization based on the RUC Availability Bids, as modified by CAISO's validation for Resource Adequacy requirements. A resource that receives a RUC instruction is compensated by the product of the RUC Award and the RUC Price of its Location. The determination of the RUC Price is similar to the determination of the Energy LMP; except that RUC Availability Bids are used for the RUC Price. The RUC Price has Energy, Loss, and Congestion components associated with it similar to LMPs that are produced in the IFM, however, the RUC Prices are not decomposed.~~RCU and RCD are priced at their respective Locational Marginal Prices (LMPs), which are calculated through the RUC optimization based on the submitted RCU and RCD bids. A resource that receives an RCU or RCD award is compensated by the product of the award and the corresponding RCU/RCD LMP at its Location. The determination of the RCU/RCD LMP is similar to the determination of the Energy LMP and includes congestion and loss components, but is based on the clearing of Reliability Capacity bids.

Note that OASIS reports RUC prices as RUC LMPs.

~~6.7.4.4~~6.8.4.3 RUC Start-Up Instructions

RUC issues binding start-up instructions only to Long-Start Units. RUC also issues advisory start-up instructions for Extremely Long-Start Resources that are validated by the CAISO

Operator through the Extremely Long- Start commitment process. For Short-Start Units, RUC evaluates the Start-Up Costs, but does not issue start-up instructions. For Short-Start Units, Start-Up Costs are eligible for Bid Cost Recovery only if the resource is actually started up as a result of a binding start-up instruction issued by RTUC.

~~Short-Start Units that are not under a contractual obligation to offer capacity are eligible to a RUC Award even though they are not issued a binding RUC Start-Up instruction in RUC.~~Short-Start Units that are not under a contractual obligation to offer capacity are eligible for RCU Awards even though they are not issued a binding RUC Start-Up instruction in RUC.

If the CAISO does not issue a Start-Up instruction to such units in the Real-Time Market, such units are compensated for their ~~RUC~~ RCU Award, but do not receive payment for RUC Start-Up Costs and Minimum Load Costs, as they were never started up. ~~Short-Start Units that are under a contractual obligation to offer capacity are not eligible to RUC Availability Payments, but are compensated for Start-Up and Minimum Load Costs through Bid Cost Recovery if they receive a Start-Up instruction in the RTM and actually start up.~~

~~6.7.4.5~~6.8.4.4 ~~RUC~~ Reliability Capacity Settlement

All ~~RUC~~ RCU and RCD Awards are paid the ~~RUC Price~~respective RCU/RCD LMP. ~~RA and~~ LRMR units do not receive RUC Awards for their ~~RA/~~LRMR Capacity. The ~~RUC~~ RCU/RCD cost allocation uses a two-tier Settlement approach.

- In the first tier, the Net ~~RUC~~ RCU Bid Cost Uplift is allocated to net virtual supply and under-scheduled load.~~positive Load deviations up to MW RUC Capacity per MW Load deviation basis.~~
- In the second tier, any remaining Net ~~RUC~~ RCU Bid Cost Uplift is allocated pro rata to all metered Demand.

- Similarly, RCD costs are allocated in two tiers to net virtual demand and over-scheduled load.

See the *BPM for Settlements & Billing* for details on Settlement. CAISO Tariff section 11.8.6.5 specifies the two allocation tiers for ~~RUC~~RCU and RCD.

~~6.7.4.6~~6.8.4.5 RUC Intertie Schedules

RUC publishes cleared Intertie schedules, which will be used as a basis for tagging in advance of real-time.

~~6.8~~6.9 Extremely Long-Start Commitment

Some Extremely Long-Start (ELS) Resources may need to receive Start-Up Instructions from CAISO before DAM results are available. According to the CAISO Tariff 27.4.1:

ELS Resources, for which commitment in the DAM does not provide sufficient time to Start-Up and be available to supply Energy during the next Trading Day will be committed manually by the CAISO Operators. Such manual commitment instructions are determined in combination with other operational expectations and reliability needs.

Extremely Long-Start Resources may be either physical resources with Start-Up Times greater than 18 hours or the contractual intertie resources that must receive commitment instructions by 0600 hours one-day ahead. Therefore, there is a need for a manual procedure to determine the commitment status of such resources two days in advance. This procedure is called the Extremely Long-start Commitment (ELC) process.

The ELC process is performed after the regular DAM processes are completed. The ELC process consists of the following steps:

1) The ELC process is initiated by the CAISO Operator.

2) If available, the CAISO Operator evaluates the non-binding advisory commitment issued by the RUC process for ELS resources. If the solution is appropriate and consistent with good utility practice, the CAISO Operator will approve the commitment. Once approved, the RUC-generated commitments will be communicated to ELS resources using the same processes as for IFM and RUC commitment of non-ELS resources. See section 6.4.6 for more information.

   Otherwise, the CAISO operator will employ the following steps to commit ELS resources:

3) ELC process for Trading day 'T+2' occurs after the completion of the DAM for Trading day 'T +1'

4) The CAISO will consider resources for ELS decision if the resource has submitted a DAM Energy bid for Trading day 'T+1'. The CAISO Operator will evaluate all the ELS submitted bids to make a decision based on Start-up Cost, Minimum Load Cost, power flow studies and Good Utility Practice.

5) Once the decision is made, the selected Extremely Long-Start Resources will receive start up instruction for Trading day ‘T+2’ by 1500 hours of Trading day ‘T’.

6) The CAISO Operator manually notifies (in the form of a phone call) the pre-committed ELS resources about their binding start up instructions as determined in the steps above.

7) The commitment instructions will not include schedules greater than the Minimum Load.

8) By 1000 hours of the Trading day ‘T+1’, pre-committed ELS units are required to submit the same bid (Bid submitted for Trading day ’T+1’) to the CAISO for Trading day ‘T+2’. This is because the original bid was used for determination of ELS commitment.

9) Depending on system conditions and resource characteristics CAISO may make decisions more that Trading day ‘T+2’ days ahead.

Refer to Operating Procedure 4420 for details on commitment of Long-Start Strategic Reserve Resources (LSSRR).

The Master File has an ELS Resource flag that indicates that the resource is subject to the ELC procedure.

Commitments of ELS Resources outside of this manual ELS commitment process must be made through Exceptional Dispatches.

7. Real-Time Processes

7.1 Differences from IFM

7.1.1 Real-Time Market Timelines

7.1.2 Real-Time Dispatch Principles

7.1.3 Flexible Ramping Product

7.1.4 Schedule Changes

7.1.5 Dispatch Priorities

7.1.6 RTM Self-Schedules

Resources may self-schedule in the RTM in addition to or without providing Energy Bids. ~~Resources with Day-Ahead Schedules that do not Bid in the RTM, are assumed to be self-scheduling their Day-Ahead Schedules.~~ The treatment of Day-Ahead Market awards in the Real-Time Market (RTM) depends on the type of award received. Day-Ahead Energy Schedules are treated as RTM self-schedules by default, while awards for Imbalance Reserve (IRU/IRD) and Reliability Capacity (RCU/RCD) create a Must-Offer Obligation (MOO) for economic energy bids in the RTM. Consistent with section 34.1.1 of the CAISO tariff, the CAISO takes the Day-Market results as inputs into the Real-Tame Market. As discussed in Section 31.8.1 of the CAISO Tariff, the CAISO enforces a constraint at each Intertie such that physical imports net of physical exports must be less than or equal to the scheduling limit at the Scheduling Point in the applicable direction. Through this ~~RUC~~ constraint the CAISO determines what portion of what Day-Ahead Schedules can have an E-Tag submitted Day-Ahead.

Accordingly, for all resources but exports, self-schedules in the real-time will be based on the IFM Energy schedules. For exports, self- schedules in real-time will be based on the ~~RUC~~ final Reliability Schedule (EN + RCU – RCD)~~schedules~~. Any self-schedule in real-time above this level will not have a day-ahead self- schedules priority.

Energy Bids are required for resources that have AS or RUC Awards, Bid or Self-Provided AS, IRU/IRD Awards or RCU/RCD Awards, or are under a Resource Adequacy Obligation. A resource's Day-Ahead Energy Schedule that does not have an associated IR or RC award, and for which no new RTM bid is submitted, will be treated as an RTM self-schedule. Furthermore, any portion of a resource's operating range that is not subject to a real-time must-offer obligation (as described in Section 7.1.6.2) may be self-scheduled.

Resources awarded Imbalance Reserve (IRU/IRD) or Reliability Capacity (RCU/RCD) in the Day-Ahead Market have a must-offer obligation in the RTM. This obligation requires the resource's Scheduling Coordinator to submit economic energy bids for the full capacity range of the award.

- Upward Capacity Awards (IRU and RCU): A resource awarded IRU or RCU capacity must submit economic energy bids for the capacity range from the top of its Day-Ahead Energy Schedule up to the full awarded upward capacity.

- Downward Capacity Awards (IRD and RCD): A resource awarded IRD or RCD capacity must submit economic energy bids for the capacity range from the bottom of its Day-Ahead Energy Schedule down to the full awarded downward capacity.

If the Scheduling Coordinator fails to submit the required economic energy bids to meet this must-offer obligation, the Scheduling Infrastructure and Business Rules (SIBR) system will automatically insert bids on behalf of the resource at its Default Energy Bid (DEB) to ensure the capacity is available for dispatch in the RTM.

In order to get TOR/ETC priorities in RTM, resources need to re-submit self-schedules of type 'ETC' or 'TOR' in RTM. Otherwise, Day-Ahead Schedules of resources roll into RTM and are protected in RTM at Self-Schedule priorities and not at 'ETC' or 'TOR' priority.

A Self-Schedule from a resource that is not committed in the DAM indicates self-commitment, i.e., the RTM does not de-commit Self-Scheduled resources. Conversely, a Self-Schedule cleared in the RTM for a resource committed by the CAISO in DA does not constitute a Self-Commitment. The RTM also does not de-commit resources with Ancillary Services Awards. The Self-Schedule, although at a higher scheduling priority than Energy Bids, may be reduced by the RTM if this is necessary to resolve network constraints. Self-Schedules may also be adjusted by the RTM as necessary to resolve any resource operational or inter-temporal Constraint violations.

The Self-Schedule is modeled as an Energy Bid with a penalty price that effectively provides scheduling priority over economic Energy Bids. The penalty price is only for modeling purposes and it does not affect the Energy component of the LMP, which is calculated by the pricing run. For Settlement purposes, RTM Self-Schedules are Price Takers; (i.e., their Energy deviation from the DAM Energy Schedule is settled at the relevant LMP).

As described in CAISO Tariff Section 34.10.1, Increasing Supply, there are several different types of Self-Schedules at different scheduling priorities. The scheduling priorities as defined in the RTM optimization to meet the need for increasing Supply as reflected from higher to lower priority are as follows:

- Non-Participating Load reduction (power balance constraint slack)

- Economic Bids submitted in the RTM, including Contingency Only Operating Reserve if activated by the CAISO Operator to provide Energy (as indicated by the Contingency Flag and the Contingency condition)

As outlined in CAISO Tariff Section 34.12.2, Decreasing Supply, the scheduling priorities as defined in the RTM optimization to meet the need for decreasing Supply as reflected from higher to lower priority are as follows:

- Non-Participating Load increase[15] (power balance constraint slack)
- Legacy Reliability Must Run (LRMR) Dispatches
- Transmission Ownership Right (TOR) Self-Schedules
- Existing transmission Contact (ETC) Self-Schedules
- Regulatory Must Run and Regulatory Must Take (RMT) Generation Self-Schedules
- Participating Load increase
- Day-Ahead Supply Schedule
- Self-Schedule submitted in the RTM
- Economic Bids submitted in the RTM

These dispatch priorities as defined in the RTM optimization may be superseded by CAISO Operator actions and procedures. A variety of conditions may require CAISO discretionary actions, for example if the Operator needs to take action to maintain reliability or to execute an Exceptional Dispatch.

If an Energy Bid is submitted with a Self-Schedule from the same resource for the same Trading Hour, the Energy Bid must start at the end of all relevant Self-Schedules stacked back-to-back in decreasing scheduling priority order. Otherwise, the Energy Bid must start at the applicable Minimum Load (zero for System Resources).

Self-committed resources are not eligible for recovery of their Start-Up Costs. Self-committed resources are also not eligible for recovery of their Minimum Load Costs during the Trading Hours when they self-schedule. However, they are still eligible for conditional recovery of unrecovered Bid Costs through the Bid Cost Recovery mechanism in Settlement.

Since Self-Provided Ancillary Services can be submitted only at the MSG Configuration for a given Trading Hour and since it is possible that that Multi-Stage Generating Resource can actually support the Self-Provided Ancillary Service amount from other configurations, Self-

[15] To the extent that "non-participating load increase" physically occurs, it would be through out-of-market sales of excess supply, since in-market remedies have already been exhausted.

Provided Ancillary Service quantities are treated as plant level quantities in the Real-Time Market. In order to accomplish this, the Self-Provided Ancillary Services on the originally submitted MSG Configuration is propagated to other Ancillary Services certified MSG Configurations for the optimization to consider in the following steps:

Step 1: Perform the Ancillary Services qualification process on the submitted MSG Configuration in the same manner as for non-Multi-Stage Generating Resources, except using the MSG Configuration's parameters such as ramp-rate, PMin and PMax.

Step 2: Transfer the qualified Ancillary Services self provision MW to other MSG Configurations with Ancillary Services certification in the same service product if these configurations have Energy Bids for that given Trading Hour. This transferred Ancillary Services self provision MW is determined by the following formula per transferred MSG Configuration,

> Transferred Self-Provided Ancillary Services = Minimum (final qualified Self-Provided Ancillary Service of bid in MSG Configuration, certified Ancillary Services capacity of transferred MSG Configuration)

Step 3: On the transferred MSG Configuration, the transferred Self-Provided Ancillary Services amount determined from step 2 will then be further qualified using the same rules in capacity and ramping qualification as for non-Multi-Stage Generating Resources (see section 4.2.1), except using the MSG Configuration's parameters such as ramp-rate, PMin and PMax.

The Multi-Stage Generating Resource will be allowed to submit a Self-Schedule on only one MSG Configuration per given Trading Hour. However, this Self-Schedule reflects the Multi-Stage Generating Resource's intention to operate at or no lower than a certain MW level, not an intention to operate in a particular MSG Configuration. Consequentially, any one of the MSG Configurations may be committed if there is a self-schedule on any of the MSG Configurations within the same Multi-Stage Generating Resource. Once submitted, the Self-Schedule is associated with all MSG Configurations of the Multi-Stage Generating Resource that have a Minimum Load below or equal to the Self-Schedule quantity. In order to provide for fair economic choice among MSG Configurations there will be adjustments to Start-Up Cost, Minimum Load Cost and related Transition Costs of affected configurations as listed below.

The rules given below apply to self-schedules:

1. For the MSG Configuration with a PMin higher than the Self-Schedule MW:
   - The Minimum Load Cost will be taken into account when considering commitment of the configuration, but will be reduced to only reflect cost of

minimum load not consumed by Self-Scheduled quantity, i.e. will be equal to Max(0, Minimum Load Cost of the transferred configuration - Minimum Load Cost of the submitted MSG Configuration);

- the Start-Up Cost will be taken into account when considering commitment of the MSG Configuration;
- Transition Cost for any transition that is incident (incoming or outgoing) into/from the MSG Configuration will be considered unless conflicting with rules 2 and 3 below.

2. For the MSG Configuration with a PMin lower than or equal to the Self-Schedule MW and a PMax higher than or equal to the Self-Schedule MW:
   - Start-Up Costs and Minimum Load Costs are treated as must-run resources (i.e. there is no Start-Up Cost and no Minimum Load Cost);
   - Ignore Transition Costs for incoming transitions;
   - Consider Transition Costs for outgoing transitions.
3. For the MSG Configuration with a PMax lower than the Self-Schedule MW:
   - Ignore Start-Up Costs;
   - Minimum Load Cost treatment is the same as in (2) above;
   - Ignore Transition Cost for any transition incident to the particular configuration.

7.2 Scheduling Coordinator Activities

7.3 CAISO Activities

The principle activities that CAISO performs are described in the following subsections.

7.3.1 Accept Real-Time Market Inputs

7.3.1.1 Energy Limits & Energy Quota Calculation

As per Section 5.1.1.2.2 of Market Instruments BPM, Daily Energy Limits (a maximum and a minimum) Minimum Daily Energy limits are not enforced for Generating Resources. These are an optional component submitted by SCs in their Day-Ahead bids, and if submitted and validated, are enforced in all DAM applications. The enforcement of daily Energy Limits is straightforward in these applications because the Time Horizon is a Trading Day. Energy Limits are also enforced in the RTM applications to assure that the Unit Commitment and Dispatch these applications perform do not violate at the end of the Trading Day the daily Energy Limits that are enforced in the Schedules produced in the DAM. CAISO is committed to honoring Energy Limit constraints unless doing so would violate reliability of the grid.

This section describes the methodology employed in RTM for deriving Energy Limits for the relevant Time Horizon so that: (a) the daily Energy Limits are not violated at the end of each Trading Day and (b) there is sufficient room between the minimum and maximum Energy Limits for optimal Dispatch.

If the Time Horizon spans a Trading Day boundary, the Energy Limits are derived in parts for each Trading Day applying the following general methodology using the data and variables applicable to the relevant Trading Day for each resource. The following concepts are used in the section:

- **Scheduled Energy Quota –** To derive a maximum Energy Limit, the scheduled Energy quota is calculated as the scheduled Energy out of the higher of the IFM or RUC schedule, from the start of the Trading Day to the end of the RTM Time Horizon. To derive a minimum Energy Limit, the scheduled Energy quota is calculated as the scheduled Energy out of the ~~lower of the IFM or RUC schedule~~final IFM Energy Schedule~~[16]~~, from the start of the Trading Day to the end of the RTM Time Horizon. The scheduled Energy quota may be negative for a minimum Energy Limit in the case of a Pumped-Storage Hydro[17] Unit scheduled to pump.

- **Unused Energy Quota –** The unused Energy quota is a pro rata allocation of unused daily Energy (daily Energy Limit minus scheduled Energy over the Trading Day) from the start of the Trading Day to the end of the RTM Time Horizon. The unused Energy quota may be negative for a minimum Energy Limit in the case of a Pumped-Storage Hydro Unit.

- **Dispatched Energy Quota –** The dispatched Energy quota is the total Energy dispatched in RTM from the start of the Trading Day to the start of the RTM Time

~~[16] Except for IFM Energy or Minimum Load Energy, a RUC schedule is not an Energy schedule.~~

[17] Minimum Energy Limit for a Pump-Storage Hydro resource reflect the maximum of pumping energy that can be consumed.

Horizon. The dispatched Energy quota may be negative in the case of a Pumped-Storage Hydro Unit dispatched in the pumping mode.

- **Energy Limit** – The Energy Limit for the RTM Time Horizon is calculated as the sum of the scheduled Energy quota and the unused Energy quota from the start of the Trading Day to the end of the RTM Time Horizon, reduced by the dispatched Energy quota from the start of the Trading Day to the start of the RTM Time Horizon. The minimum Energy Limit may be negative in the case of a Pumped-Storage Hydro Unit.

Energy Limits are enforced in the RTM applications as soft constraints, i.e., with lower penalty costs than other constraints, such as network constraints and Exceptional Dispatches. Exceptional Dispatches, in particular, and also Outages and derates may result in Energy Limit violations.

The described methodology enforces the daily Energy Limits as a dynamically adjusted rolling average over the course of a Trading Day, providing room for optimal refinement of the DAM Schedules in Real-Time. Aside from the effect of other binding constraints that may conflict with the Energy Limit constraints, the methodology assures a feasible outcome, but only when Dispatch Instructions are followed accurately, and neither AGC actions, contingencies nor Exceptional Dispatches cause Energy Limit violations, since the formulation involves only Instructed Imbalance Energy.

Consequently, Energy Limits may be violated due to the regulating action of units on Regulation and due to Uninstructed Deviations driving the Dispatch Instructions via the State Estimator feedback. The method attempts to recover any Energy outside the rolling average limits over the course of a Trading Day, however, this may not be possible if Uninstructed Deviations persist.

This means that if a resource deviates and causes the Energy Limits to exceed the rolling average Energy Limits but not the total Energy Limit for the day, then the solution attempts to reduce the Dispatch of the resource for future Dispatches in order to recover or conserve the Energy Limits in the future. If the total Energy Limit has been hit then the recovery is not possible.

7.4 MPM for Real-Time

7.5 Hour-Ahead Scheduling Process

7.6 Real-Time Unit Commitment and Fifteen-Minute Market

7.6.1 Real-Time Unit Commitment Inputs

7.6.2 Real-Time Ancillary Services Procurement

To the extent possible, the CAISO attempts to procure 100 percent of Ancillary Services in the Day-Ahead Market. CAISO procures AS in Real-Time using the FMM, and for Non-Dynamic System Resources with hourly block Bids only, the HASP process, as needed to replenish Operating Reserves or Regulation, should the AS procured in the forward markets be called in Real-Time or become unavailable due to Outages or derates. The CAISO procures AS in the Real-Time as needed to satisfy the NERC requirements. The resources committed by the CAISO in Real-Time to provide AS are eligible for Start-Up and Minimum Load Cost compensation through the BCR process as specified in Section 11.8 of the CAISO Tariff.

AS procured in RT are paid based on the ASMP. See Section 4.4 for details of the ASMP payment.

For purposes of the Real-Time AS procurement, all resources certified to provide Spinning or Non-Spinning Reserves (Operating Reserves) for which an Energy Bid has been submitted or an Energy Bid has been generated by SIBR, are deemed available to CAISO to provide Operating Reserves. Real-Time procurement and pricing of Operating Reserves is performed using dynamic co-optimization of Energy and Spinning and Non-Spinning Reserve. If the Scheduling Coordinator does not submit a Bid for Operating Reserves but has submitted an Energy Bid, the CAISO inserts a Default AS Bid Price on their behalf for all Operating Reserve to allow the CAISO to procure either Energy or Operating Reserve up to the maximum bid-in level as represented by the Energy Bid. This is irrespective of whether that resource has been awarded an IFM AS award. In any case, any Energy Bid associated with an Ancillary Services Bid for the same Resource ID of a Non-Dynamic System Resource, the ISO will not utilize the Energy Bid in the clearing the RTM to Dispatch Energy, unless the Resource ID is also awarded Ancillary Services for that interval.

For Regulation, all resources certified and capable of providing Regulation that have been awarded Regulation in Day-Ahead Market or have submitted a Bid to provide Regulation in the Real-Time Market shall also submit applicable Regulation Bids up to their certified value. Otherwise, SIBR will create a Default AS Bid Price for the remaining certified quantity. (Section 34.2.2 of the CAISO Tariff.)

CAISO will procure in the 15-minute market additional Ancillary Services only from resources that are certified to provide these services.

RTM evaluates AS needs and procures any shortfall using the RTUC application (on a 15-minute basis). Real-Time AS requirements are calculated within RTM based on system/regional requirements determined by WECC and Real-Time operating conditions.

Resources committed by the CAISO in Real-Time to provide additional Spinning Reserve and offline resources providing additional Non-Spinning Reserve are both eligible for Bid Cost Recovery. Additionally, the Real-Time procurement of AS does not result in a withdrawal of any earlier ~~RUC Availability~~Reliability Capacity Payments for ~~RUC~~ RCU/RCD Awards, i.e., ~~RUC~~ Reliabiity Capacity procured in the DAM can be used for AS procurement in RTM. Dispatched Energy from resources selected to provide AS in Real-Time are settled as Instructed Imbalance Energy.

Real-Time Regulation procurement may be necessary to recover regulating margin lost due to Outages or derates. Regulation procured in RTM is paid the 15-minute ASMP at the location of the resource. SCUC and SCED use the revised Regulation ranges in allocating AS to the Energy Bid in subsequent runs, and the Regulation deficiency report is revised accordingly.

7.7 Short-Term Unit Commitment

7.8 Real-Time Economic Dispatch

7.9 Real-Time Contingency Dispatch

7.10 Real-Time Manual Dispatch

7.10.1 Real-Time Manual Dispatch Inputs

~~7.10.2~~

7.10.2 Real-Time Manual Dispatch Constraints & Objectives

7.10.3 Real-Time Manual Dispatch Outputs

The CAISO Operator manually initiates communication of manual Dispatch Instructions through ADS and the merit order list is updated accordingly.

While the RTMD mode is being used for Dispatch, a uniform five-minute MCP is produced for all PNodes based on the merit order Dispatch. Until RTMD is actually run and RTMD-based Dispatch Instructions are issued after RTED fails to converge, all five-minute Dispatch Interval LMPs are set to the last LMP at each PNode produced by the last RTED run that converged.

7.10.4 Procedures in the Event of Failure of the RTUC/RTED Market Processes.

Consistent with Section 7.7.5, and 7.7.6 of the CAISO Tariff, in the event of a Market Disruption of the RTUC/RTED, the CAISO will follow the procedures described below. Market Disruption in this context refers to events where the market software applications fail to operate and are unable to send instructions to market participants.

7.10.4.1 RTED (Real-Time Economic Dispatch) Failure

In case of a RTED failure, the CAISO may do nothing and may rely on the binding dispatch results of the previous successful RTED run, i.e., resources should stay at the last good DOT. The binding dispatch results will not be sent through ADS for the failed interval. The binding dispatch results of the previous successful RTED run will also be used for expected energy allocation purposes. Flexible ramping awards shall have the value from the last good FMM interval, except the flexible ramping pass group information. The pass group information will not be determined during a RTED failure since the pass group information associated with RTED runs are not used for settlement purposes.

To avoid a full market disruption of a five-minute interval, the ISO may turn off the Forbidden Operating Region functionality for a resource(s) on which the application of the functionality previously caused a failure of a RTED run, then the applicable Dispatch will be the 5-minute Dispatch issued without the Forbidden Operating Region functionality for the affected five minute interval(s).

The CAISO may take other actions to address such Market Disruptions, including implementing Exceptional Dispatches. See section 7.11 for more detail.

7.10.4.2 RTUC failure (including HASP)

In case of a RTUC, FMM or HASP Market Disruption, consistent with Section 7.7.15 and 34.4 of the ISO Tariff, the following procedure will apply:

- (1) Internal generators and tie generators (Dynamic System Resources): Consistent with Section 34.4 of the ISO Tariff, if there is a complete disruption of the RTUC, including the FMM and HASP, the ISO will use the last valid RTUC MWs for purposes of settling fifteen minute schedules, and prices as specified in section 8.2. For AS Awards, the CAISO will rely on the day-ahead ancillary service results relevant to the 15-minute interval in the failed RTUC run as the fall back results for dispatch, and prices as specified in section 8.2. Flexible ramping awards will be considered to have a zero MW value. However, the ISO will use the flexible ramping pass group information from the last valid RTUC for settlement purposes.

- (2) For Intertie resources in case of a failed RTUC run (including HASP): For energy MW the CAISO will rely on the HASP results for settlement purposes if available. If not available, the CAISO will use the final day-ahead Reliability Schedule (EN + RCU – RCD)~~RUC results~~ relevant to the HASP hour in the failed run as the fall back results for settlement. CAISO will use prices as specified in section 8.2.

- (3) For intertie resources in cases of a disruption of the FMM for purposes of clearing the interties only: The CAISO may experience or institute a market disruption of the Fifteen Minute Market for purposes of clearing the interties only and keep the remaining FMM functionality operational. During such times, the CAISO will only suspend bidding into the Real-time Market for the FMM by intertie resources and only after notifying market participants that the FMM has been interrupted for this purpose. During such times, Scheduling Coordinators will only be allowed to submit Self-Scheduled Hourly Blocks or Economic Hourly Block Bids, and will not be allowed to submit Economic bid hourly block with a single intra-hour schedule change or Economic bid with participation in the fifteen-minute market in for intertie resources. Scheduling Coordinators will be permitted to submit bids for the FMM for internal resources and Dynamic System Resources. For settlement purposes HASP Block Intertie Schedules for Non-Dynamic System Resources will be settled based on the individual fifteen-minute interval LMPs as specified in section 8.2. Hourly ancillary service imports will be settled based on the prices specified in section 8.2. Supply from internal resources and Dynamic System Resources will be untouched and continue to settle based on the applicable tariff rules. Demand resources settled based on the Load Aggregation Points will be settled based on the RTD Default or Custom LAP Price as defined in Section 27.2.2.2 of the CAISO tariff. Upon cessation of the Market Disruptions, the CAISO shall issue a notice to Scheduling Coordinators providing sufficient advance notice of the first RTM interval in which the above-defined actions will not apply.

- The CAISO may take other actions to address such Market Disruptions, including implementing Exceptional Dispatches. See section 7.11 for more detail.

The binding Ancillary Service results will not be sent through ADS for the failed interval. For the after-the-fact correction and settlement purpose, CAISO will do the following,

1. Expected energy allocation will use the day-ahead Ancillary Service Award for that interval;

2. There will be no real-time Ancillary Service charge or payment for that interval since all Ancillary Service awards fall back to day-ahead awards;

3. For a Trading Hour with only HASP failure:

   3.1. For physical Energy schedules, there will not be any settlement for that Trading Hour since all Intertie schedules fall back to Day-Ahead Market. All Real-Time Market Energy beyond the Day-Ahead Market Schedule will be eventually treated as Operational Adjustment for Settlements purposes and settled at RTD prices.

   3.2. For Virtual Bids on the Interties, any Virtual Award will be offset by an equal credit or debit for a net zero settlement.

8. Tagging

8.1 What is an E-Tag?

8.2 Who Is Required to E-Tags?

8.3 E-Tag Tools

8.4 What goes into an E-Tag?

8.5 Tagging and Validation Timelines

8.5.1 Tagging Validation and CAISO Market Awards

8.5.1.1 Day-Ahead and Real Time

It is highly recommended that Scheduling Coordinators tag their ~~ISO Day Ahead RUC energy~~final day-ahead reliability schedules (EN + RCU - RCD) and IFM AS market awards following the publishing of the Day Ahead market results. If for any reason the ISO HASP market advisory dispatch fails, the market participant is required to supply their full Reliability Schedule and awarded ancillary services.~~RUC energy and ancillary service awards.~~

Tagging your final day-ahead Reliability Schedule~~ISO DA RUC market award~~ to allow E-Tags to be approved or denied by the ISO also allows any issue on the E-Tag to be reviewed and fixed before real time. Consistent with WECC Regional Criterion, for CAISO Day Ahead awards of market priority type DALPT for which the CAISO is responsible for the contingency reserves, the corresponding E-Tag Energy Product Type shall equal Firm Provisional (G-FP[1]). This practice also provides important information to the sink BA of the final ~~RUC~~ Reliability Schedule and the firmness of the energy. The ISO is required to act on each E-Tag upon submittal. According to the NERC INT-006-4 requirement: "Each Transmission Service Provider shall approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined . . . ."

[1] G-FP: Firm Provisional Energy. This product may be interrupted only if the interruption is within the recall time and for conditions allowed by applicable provisions governing interruption of service, as mutually agreed to by the parties. A G-FP product cannot be interrupted for economic reasons.

8.6 Emergency and Contingency Events

8.7 Ancillary Services

Providing ancillary services and other day-ahead capacity products across the interties requires an E-Tag as well. After certification, scheduling coordinators may bid and be awarded the following capacity products on interties:

- Ancillary Services (Spinning Reserve, Non-Spinning Reserve, and Regulation)
- Imbalance Reserves (IRU and IRD)
- Reliability Capacity (RCU and RCD)~~spin, non-spin and regulation across the interties in the day-ahead market or in real-time during HASP and FMM.~~

These day-ahead awards reserve transmission capacity for potential energy dispatch in the Real-Time Market. The following tagging principles apply to all these capacity products:

- A "capacity-type" E-Tag must be submitted for the award. The energy profile (ENR) on this initial tag must be zero.
- The transmission profile (TRAN) on the E-Tag must be greater than or equal to the sum of the resource's Day-Ahead Energy Schedule plus all of its awarded capacity (AS, IRU, and RCU). This ensures the total potential energy delivery does not exceed the reserved transmission.
- If the awarded capacity is dispatched as energy in real-time, the Scheduling Coordinator must update the energy profile (ENR) on the E-Tag to reflect the dispatched energy amount.

~~For ancillary service static awards, a capacity type E-Tag must be used and the energy profile in the E-Tag should be zero. When energy is actually dispatched and delivered the E-Tag shall be updated at that time, with the dispatched amount.~~

For ancillary service dynamic awards, a dynamic type E-Tag must be used. If the dynamic resource has an energy award, that MW value should be in the energy profile. ~~The dynamic transmission profile should be no less than the total MW value of the bids submitted for energy and ancillary services (Total market awards for the dynamic and pseudo tie resources will be limited by the transmission profile on the E-Tag(s).). If the awarded capacity is dispatched as energy then the dynamic E-Tag energy profile shall be updated within 60 minutes after the hour is over to reflect the final integrated quantity of energy delivered, inclusive of both awarded~~

~~energy and ancillary service dispatched energy.~~ A single dynamic or pseudo type tag may be used for energy and ancillary services for dynamic and pseudo tie resources.

Ancillary service awards require firm transmission on all line segments on the transmission allocation section of the E-Tag. This requirement applies to both static and dynamic transfers. For detailed instructions on tagging ancillary services, consult Operating Procedure 2510.