Business Practice Manual for Market Operations

Version 1054

Revised: ~~May 1, 2026~~July 29, 2026

Approval History

Approval Date: March 23, 2009

Effective Date: March 31, 2009

BPM Owners: Tricia Johnstone and Michael Martin

BPM Owner's Title: Director, Operations Readiness and Principal, System Operations

Revision History

Version	PRR	Date	Description
105	1678	7/29/2026	PRR 1678 Clarification on how storage resources are subject to ancillary service state of charge constraints and envelope constraints
104	1669 1668 1666 1661 1653	5/1/2026	PRR 1669 New day-ahead market enhancements configurable parameters PRR 1668 Initial version of the market operations BPM changes for the day-ahead market enhancements and extended day-ahead market initiatives PRR 1666 Various updates related to aggregate capability constraints PRR 1661 New long start resource min down time awareness enhancement PRR 1653 Real Time market High and low unit operating limit usage for Regulation
103	1650 1641	11/24/2025	PRR 1650 New Market Automation to prevent Market Disruptions in RTD and STUC PRR 1641 Ability for CAISO to initiate verification from resource owner
102	1627	6/25/2025	PRR 1627 Adding state of charge to flexible ramping awards determination

Version	PRR	Date	Description
101	1611	3/26/2025	PRR 1611 Convergence bidding is not permitted on intertie nodes
	1612		PRR 1612 Stage 2 variable energy resource and aggregate capability constraints limits
	1613		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	12/2/2024	PRR 1593 Change to price correction reporting
	1590		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
96	1570	7/1/2024	PRR 1570 Details on new process to establish Wheeling Through Priority as part of the TSMSP project
	1568		PRR 1568 Clarifying tagging requirements in support of resource sufficiency evaluation Phase 2 Project
	1567		PRR 1567 Updates to constraints related to the impact of ancillary service awards on state of charge on storage resources
	1556		PRR 1557 Two minor updates related to multistage generators functionality
	1557		PRR 1556 Clarification on hybrid dynamic limits submission requirements
95	1552	4/9/2024	PRR 1552 Clarification on Number of Historical Days Used in the Mosaic Quantile Regression
	1547		PRR 1547 Clarification to ancillary service state of charge constraint and bid cost recovery
	1541		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

Version	PRR	Date	Description
93	1526 1527 1530 1533 1536 1542	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)
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	1406 1501 1597	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

Version	PRR	Date	Description
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
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

Version	PRR	Date	Description
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.
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)

Version	PRR	Date	Description
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.
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

Version	PRR	Date	Description
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.

Version	PRR	Date	Description
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

Version	PRR	Date	Description
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.

Version	PRR	Date	Description
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

Version	PRR	Date	Description
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

Version	PRR	Date	Description
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.

Version	PRR	Date	Description
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

TABLE OF CONTENTS

1. Introduction 31

1.1 Purpose of CAISO Business Practice Manuals 31

1.2 Purpose of this Business Practice Manual 31

1.3 References 32

2. Market Operations Overview 33

2.1 Market Entities 33

2.1.1 CAISO 33

2.1.2 Scheduling Coordinators 34

2.1.3 Participating Generators 34

2.1.4 Constrained Output Generator 34

2.1.5 Multi-Stage Generating Resources 35

2.1.6 Participating Loads 37

2.1.7 Non-Participating Loads 45

2.1.8 Utility Distribution Companies 45

2.1.9 Metered Subsystems 45

2.1.10 Balancing Authority Areas 46

2.1.11 Participating Transmission Owners 47

2.1.12 System Resource 48

2.1.13 Non-Generator Resources 48

2.1.14 Pseudo-Tie 51

2.1.15 Use-Limited Resources 51

2.1.16 Conditionally Available Resource 82

2.1.17 Non-Dispatchable Resource 83

2.1.18 Run-of-River Hydro (ROR) 85

2.1.19 Co-Located Resources 86

2.1.20 High Sustainable Limit (HSL) 90

2.1.21 Hybrid Resources 90

2.1.22 Master and Subordinate aggregate capability constraints (ACCs) 93

2.2 Products & Services 98

2.2.1 Energy 98

2.2.2 Ancillary Services 99

2.2.3 Residual Unit Commitment Capacity 99

2.2.4 Congestion Revenue Rights 100
2.3 CAISO Markets 100
2.3.1 Day-Ahead Market Processes 102
2.3.2 Real-Time Processes 104
2.4 Roles & Responsibilities 106
2.4.1 Utility Distribution Companies 106
2.4.2 Metered Subsystems 107
2.4.3 Participating Transmission Owners Information 109
2.4.4 Participating Generators & Participating Loads 110
2.4.5 Scheduling Coordinator Responsibilities 110
2.5 Market Information 113
2.5.1 Resource Static Data 113
2.5.2 Bids 113
2.5.3 Inter-SC Trades 120
2.5.4 Existing Transmission Contracts, Transmission Owner Rights, & Converted Rights 121
2.5.5 Scheduling Priorities for Exports, Load, and Wheels 121
2.5.6 Real-time Price during tight system conditions 135
2.5.7 Reliability Demand Response Dispatch and Real-time Price 136
2.5.8 Minimum state of charge (MSOC) 137
2.5.9 Sustained Energy Requirements for Storage Resources with Regulation Awards 137
3. Full Network Model 139
3.1 Model Description 139
3.1.1 Real-Time Data 141
3.1.2 Generation Distribution Factors 142
3.1.3 Modeling Point 143
3.1.4 Load Distribution Factors 143
3.1.5 Aggregated Pricing Nodes 145
3.1.6 Losses 146
3.1.7 Nomograms 151
3.1.8 Transmission Element & Transmission Interfaces 153
3.1.9 Scheduling Points 155
3.1.10 Unscheduled Flow Estimation 155

3.1.11 Nodal Group Limit Constraints 156
3.1.12 Controllable Devices Modeling 159
3.1.13 Generator Contingency and Remedial Action Scheme modeling 160
3.1.14 Aggregated Capability Constraint for Co-Located Resources 161
3.2 Locational Marginal Prices 164
3.2.1 LMP Disaggregation 165
3.2.2 System Marginal Energy Cost 171
3.2.3 Marginal Cost of Losses 171
3.2.4 Marginal Cost of Congestion 172
3.2.1 Reliability Capacity Pricing 172
3.2.2 Imbalance Reserve Pricing 173
3.2.3 Flexible Ramp Up/Down Marginal Pricing 173
3.3 Market Interfaces 175
4. Ancillary Services 176
4.1 Ancillary Services Regions 176
4.1.1 Ancillary Services Region Definition 176
4.1.2 Ancillary Services Region Change Process 180
4.2 Ancillary Services Requirements 180
4.2.1 Self-Provided Ancillary Services 183
4.2.2 Conversion of Conditionally Qualified SPAS to Energy 186
4.2.3 Conversion of Conditionally Unqualified SPAS to Qualified SPAS 187
4.2.4 Other Details of SPAS 187
4.2.5 Ancillary Service Award Allocation on Energy Bids 188
4.2.6 Regulation Up & Down Requirements 191
4.2.7 Operating Reserve Requirements 192
4.2.8 Maximum Upward Capacity Constraint 194
4.2.9 Ancillary Service Constraints for Storage Resources 194
4.3 Ancillary Services Procurement 200
4.3.1 Ancillary Services Procurement in Day-Ahead Market 203
4.3.2 Ancillary Services Procured in Real-Time 205
4.3.3 Manual real-time contracting for ancillary services or unloaded resource capacity 206
4.4 Ancillary Services Marginal Prices 206

4.4.1 Ancillary Services Pricing in Event of Supply Insufficiency 208
4.5 Ancillary Services Considerations 215
4.6 Ancillary Services Certification & Testing Requirements 218
4.6.1 Regulation Certification & Testing Requirements 218
4.6.2 Spinning Reserve Certification & Testing Requirements 222
4.6.3 Non-Spinning Reserve Certification & Testing Requirements 222
5. Existing Transmission Contracts, Converted Rights & Transmission Ownership Rights 224
5.1 Continuation of Rights & Obligations 224
5.1.1 Existing Transmission Contracts 224
5.1.2 Converted Rights 225
5.1.3 Non-Participating Transmission Owners 226
5.1.4 Transmission Ownership Rights 226
5.1.5 TOR Scheduling Time Line Requirements 227
5.1.6 TOR Scheduling Requirements 228
5.1.7 ETC and CVR Scheduling Time Requirement 230
5.1.8 ETC and CVR Scheduling Requirements 232
5.1.9 Scheduling Priority for Transmission Rights 233
5.1.10 ETC, CVR & TOR Settlement 234
5.1.11 Transmission Rights & Curtailment Instructions (TRTC) 235
5.1.12 ETCs, CVRs and TORs Treatment in the Release of CRRs 237
5.2 Available Transfer Capability Calculation 237
5.2.1 ATC Calculation before DAM Closes 237
5.2.2 ATC Calculation After DAM Completes & Before RTM Closes 238
5.2.3 ATC Calculation After RTM Completes 239
6. Day-Ahead Market Processes 240
6.1 Pre-Market Activities 240
6.1.1 Congestion Revenue Rights 240
6.1.2 Full Network Model Build 240
6.1.3 Bid Information 240
6.1.4 Outage Information 240
6.1.5 CAISO Demand Forecast Information 241
6.1.6 Determine Total Transfer Capability 242

6.1.7 Before Day-Ahead Market is Closed 242
6.1.8 Overgeneration Condition 243
6.1.9 IFM Initial Conditions 244
6.2 Day-Ahead Market Timeline 246
6.3 Scheduling Coordinator Activities 247
6.3.1 Submit Bids 247
6.3.2 Interchange Transactions & E-Tagging 248
6.3.3 Respond to Day-Ahead Market Published Schedules & Awards 251
6.4 CAISO Activities 251
6.4.1 Accept Day-Ahead Market Inputs 251
6.4.2 Disseminate Pre-Market Information 252
6.4.3 Disseminate Post Market Close Information 253
6.4.4 Procedures for Closing the Day-Ahead Market 253
6.4.5 Execute Day-Ahead Market Applications 254
6.4.6 Publish Reports to Scheduling Coordinators 254
6.4.7 Resource Commitment 257
6.5 Market Power Mitigation for IFM 258
6.5.1 Decomposition method 259
6.5.2 Treatment of Legacy RMR Resources 261
6.5.3 Competitive Path Criteria 261
6.5.4 Default Energy Bids 263
6.5.5 Bid Adder for Frequently Mitigated Units 263
6.5.6 Mitigation Exemptions for Small Storage Resources 264
6.6 Integrated Forward Market 265
6.6.1 IFM Inputs 267
6.6.2 IFM Constraints & Objectives 270
6.6.3 Co-optimization of Energy, Ancillary Services, and Imbalance Reserves 280
6.6.4 Market Clearing 280
6.6.5 Adjustment of Non-Priced Quantities in IFM 281
6.6.6 IFM Outputs 307
6.6.7 Energy Settlement 308
6.6.8 Imbalance Reserve Product 310

6.7 Market Power Mitigation for RUC ... 312
6.7.1 Decomposition method ... 313
6.7.2 Competitive Path Criteria ... 313
6.7.3 Default Bids ... 314
6.8 Residual Unit Commitment ... 314
6.8.1 RUC Objective ... 315
6.8.2 RUC Inputs ... 316
6.8.3 RUC Execution ... 327
6.8.4 RUC Outputs ... 328
6.9 Extremely Long-Start Commitment ... 330
7. Real-Time Processes ... 331
7.1 Differences from IFM ... 332
7.1.1 Real-Time Market Timelines ... 336
7.1.2 Real-Time Dispatch Principles ... 338
7.1.3 Flexible Ramping Product ... 338
7.1.4 Schedule Changes ... 350
7.1.5 Dispatch Priorities ... 356
7.1.6 RTM Self-Schedules ... 357
7.1.7 Calculation of MCP ... 361
7.2 Scheduling Coordinator Activities ... 362
7.2.1 Submit Bids ... 362
7.2.2 Interchange Transactions & E-Tagging ... 362
7.2.3 Respond to Commitment & Dispatch Instructions ... 363
7.3 CAISO Activities ... 368
7.3.1 Accept Real-Time Market Inputs ... 368
7.3.2 Close Real-Time Market ... 374
7.3.3 Execute Real-Time Applications ... 374
7.3.4 Publish Real-Time Market Reports to Scheduling Coordinators ... 376
7.4 MPM for Real-Time ... 376
7.5 Hour-Ahead Scheduling Process ... 378
7.5.1 HASP Inputs ... 378
7.5.2 HASP Constraints & Objectives ... 380
7.5.3 HASP Outputs ... 380

7.6 Real-Time Unit Commitment and Fifteen-Minute Market 382
7.6.1 Real-Time Unit Commitment Inputs 383
7.6.2 Real-Time Ancillary Services Procurement 383
7.6.3 Real-Time Unit Commitment Constraints & Objectives 385
7.6.4 Real-Time Unit Commitment Outputs 387
7.6.5 Real-Time Unit Commitment Pricing 388
7.7 Short-Term Unit Commitment 388
7.7.1 Short-Term Unit Commitment Inputs 389
7.7.2 Short-Term Unit Commitment Constraints & Objectives 389
7.7.3 Short-Term Unit Commitment Outputs 390
7.8 Real-Time Economic Dispatch 390
7.8.1 Real-Time Economic Dispatch Inputs 392
7.8.2 Real-Time Economic Dispatch Constraints & Objectives 394
7.8.3 Real-Time Economic Dispatch Outputs 410
7.9 Real-Time Contingency Dispatch 417
7.9.1 Real-Time Contingency Dispatch Inputs 420
7.9.2 Real-Time Contingency Dispatch Constraints & Objectives 420
7.9.3 Real-Time Contingency Dispatch Locational Marginal Prices and Load Forecast 421
7.9.4 Real-Time Contingency Dispatch Outputs 422
7.10 Real-Time Manual Dispatch 422
7.10.1 Real-Time Manual Dispatch Inputs 424
7.10.2 Real-Time Manual Dispatch Constraints & Objectives 424
7.10.3 Real-Time Manual Dispatch Outputs 425
7.10.4 Procedures in the Event of Failure of the RTUC/RTED Market Processes 425
7.11 Exceptional Dispatch 429
7.11.1 System Reliability Exceptional Dispatches 430
7.11.2 Other Exceptional Dispatch 431
7.11.3 Transmission-Related Modeling Limitations 431
7.11.4 Holding and Charging State-of-Charge (SOC) 432
8. Tagging 437
8.1 What is an E-Tag? 437
8.2 Who Is Required to E-Tags? 438

8.2.1 Imports/Exports 438
8.3 E-Tag Tools 440
8.4 What goes into an E-Tag? 441
8.4.1 Valid Transmission and Energy Profiles 442
8.4.2 Capacity Profile for Ancillary Services 443
8.4.3 Scheduling Paths 443
8.4.4 Static Schedules or Normal E-Tags 443
8.5 Tagging and Validation Timelines 444
8.5.1 Tagging Validation and CAISO Market Awards 444
8.5.2 When to submit E-Tags 446
8.5.2.1 Hourly bid option intertie resources 446
8.5.2.2 15-minutes bid option intertie resources 446
8.5.3 E-Tag Adjustments and curtailments 447
8.5.4 EIM Transfers 449
8.6 Emergency and Contingency Events 449
8.7 Ancillary Services 449
9. Post Market Activities 450
9.1 Price Validation 450
9.1.1 Market Validation 452
9.1.2 General Scope of Price Corrections 452
9.1.3 Scope of Price Corrections for DAM 453
9.1.4 Scope of Price Corrections for RTM 454
9.1.5 Price Correction Process 454
9.1.6 Procedures 456
9.2 Administrative Pricing 458
9.2.1 Administrative Pricing for Day-Ahead Market 459
9.2.2 Administrative Pricing for Real-Time Market 460

Attachments:

Attachment A: Market Interfaces

Attachment B: Competitive Path Assessment

Attachment C: Expected Energy Calculation

Attachment D: Commitment Cost Determination

Attachment E: Price Corrections Make Whole Payments

Attachment F: CRR Settlement Rule

Attachment G: Process for Addressing Market Issues

Attachment H: Circular Schedule

Attachment I: Implementation of Marginal Cost of Losses and Transmission Losses for Facilities on the CAISO Controlled Grid outside the CAISO Balancing Authority Area

Attachment J: Calculation of Weekly Mileage Multipliers

List of Exhibits:

Exhibit 2-1: CAISO Markets – Overview Timeline ..... 101~~109~~
Exhibit 3-1: Generator Telemetry Data from EMS to RTM ..... 141~~150~~
Exhibit 3-2: Load Telemetry Data from EMS to RTM ..... 141~~150~~
Exhibit 3-3: Connectivity Node Data from SE to RTM ..... 141~~150~~
Exhibit 3-4: Load Aggregation Point ..... 145~~154~~
Exhibit 3-5: Modeling Point ..... 145~~154~~
Exhibit 3-6: CAISO Power Balance Relationship ..... 147~~156~~
Exhibit 3-7: Marginal Losses - Conceptual Model ..... 150~~159~~
Exhibit 3-8: Nomogram ..... 153~~162~~
Exhibit 3-9: Market Interfaces ..... 175~~184~~
Exhibit 4-1: Summary of Initial AS Regions ..... 178~~187~~
Exhibit 4-2: Qualification Process of Submissions to Self-Provide an AS ..... 186~~195~~
Exhibit 4-3: Ancillary Service Award Allocation on the Energy Bid ..... 190~~199~~
Exhibit 4-4: Example for Spinning Reserve AS ..... 207~~216~~
Exhibit 6-1: Day-Ahead Market Timeline ..... 247~~255~~
Exhibit 6-3: Day-Ahead Market Clearing Price for Energy – Ignoring Marginal Losses & Congestion ..... 281~~292~~
Exhibit 6-4: Capacity Available for RUC ..... **Error! Bookmark not defined.**~~343~~
Exhibit 6-5: RUC Start Up, Minimum Load, & Availability Bid Eligibility ..... 323~~344~~
Exhibit 7-1: HASP/STUC/RTUC Timelines ..... 337~~359~~
Exhibit 7-2: Real-Time Market Clearing Price for Energy (Ignoring Marginal Losses & Congestion) ..... 361~~383~~
Exhibit 7-3: Real-Time Applications ..... 374~~396~~
Exhibit 7-4: Advisory Schedule from HASP ..... 382~~404~~
Exhibit 7-5: RTED Timeline ..... 392~~414~~
Figure 1: Example of Ancillary Service award impact on an EOH SOC bid ..... 406~~428~~
Figure 2: RTED end-of-horizon example 1 ..... 408~~430~~
Figure 3: RTED end-of-horizon example 2 ..... 408~~430~~

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

CAISO is a non-profit public benefit corporation that:

- Has Operational Control of transmission facilities of all Participating Transmission Owners
- Is the Balancing Authority Area Operator for the CAISO Balancing Authority
- Administers the CAISO Markets

2.1.2 Scheduling Coordinators

It is important to note that all business with the CAISO Markets, except for acquisition and holding of Congestion Revenue Rights (CRRs), must be conducted through CAISO-approved and registered entities called Scheduling Coordinators (SCs). The primary responsibilities of SCs include as applicable:

- Represent Generators, Load-Serving Entities, Proxy Demand Resources (PDR), Proxy Demand Resource-Load Shift Resource (PDR-LSR), Reliability Demand Response Resources (RDRR), importers, and exporters
- Provide NERC tagging data
- Submit Bids[1] and Inter-SC Trades
- Settle all services and Inter-SC Trades related to the CAISO Markets
- Ensure compliance with the CAISO Tariff
- Submit annual, weekly, and daily forecasts of Demand

2.1.3 Participating Generators

Please refer to Tariff Appendix A for participating generator definition.

A Participating Generator must register with an SC who acts on the Participating Generator's behalf for the sale of Energy or Ancillary Services into the CAISO Markets. All CAISO Markets transactions engaged in by the SC for specific Participating Generators is settled with the applicable SC.

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).

[1] Including Virtual Bids

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. 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

Generating Units and Dynamic Resource-Specific Resources may register and qualify as Multi-Stage Generating Resources pursuant to the requirements specified in Section 27.8 of the CAISO Tariff. Multi-Stage Generating Resources are Generating Unit or Dynamic Resource-Specific System Resource that for reasons related to its technical characteristics can be operated in various MSG Configurations such that only one such MSG Configuration can be operated in any given Dispatch Interval. Subject to the requirements in Section 27.8 of the CAISO Tariff, the following technical characteristics qualify a Generating Unit or Dynamic Resource-Specific System Resource as a Multi-Stage Generating Resource if the resource; (1) is a combined cycle gas turbine resource; (2) is a Generating Unit or Dynamic Resource-Specific System Resources with multiple operating or regulating ranges but which can operate in only one of these ranges at any given time; or (3) has one or more Forbidden Operating Regions. Metered Subsystems, Pumped-Storage Hydro Units, and Pumping Loads, and System Resources that are not Dynamic Resource-Specific System Resources do not qualify as Multi-Stage Generating Resources.

This modeling approach allows for a specified number of discrete states (one Off state and at least two On states with different resource configurations). Each on-line state represents a MSG Configuration in which the Multi-Stage Generating Resource can operate. Operating limits and

technical characteristics are defined for each MSG Configuration separately and are retained in the Master File. Each MSG Configuration is modeled as a logical generator with its own individual components such as operating limits, ramp rate, Minimum Load Cost, Transition Costs, and Energy Bids.

The Transition Matrix contained in the Master File includes a prescribed set of feasible MSG Transitions that indicate the feasible transition from one MSG Configuration to another. Transition Costs and Transition Times, defined in the registered Transition Matrix can be different for each defined transition. Transitions that are not registered in the Transition Matrix are not considered by the CAISO Market processes. Each of the MSG Configurations have specified minimum on-state time, minimum off-state time.

The following are some of the characteristics of Multi-Stage Generating Resources:

- The Economic Bids and Self-Schedules are defined at the MSG Configuration level.

- The outage information from outage management system is obtained at the MSG Configuration and the Generating Unit level (i.e. plant level). The market applications use PMax derate or PMin uprate information from outage management system at the MSG Configuration level for most processes; however it uses outage information at the overall plant level for validating Exceptional Dispatch instructions.

- The Scheduling Coordinator may register up to six MSG Configurations without any limitation on the number of transitions between the registered MSG Configurations in the Transition Matrix. If the Scheduling Coordinator registers seven or more MSG Configurations, then the Scheduling Coordinator may only include two eligible transitions between MSG Configurations for upward and downward transitions, respectively, starting from the initial MSG Configuration in the Transition Matrix.

- In addition, no Forbidden Operating Region (FOR) is allowed in any MSG Configuration, and Operational Ramp Rate curves are limited to two segments within a given MSG Configuration. Consequently, the ramp-rate de-rate from outage management system will be limited to two segments for a given MSG configuration accordingly.

- Separate Minimum Up Time (MUT) and Minimum Down Time (MDT) constraints can be enforced at both the plant and individual MSG Configuration levels. In addition, MUT and MDT constraints may be specified for a group of MSG Configurations. Specific features are as follows:

    - Plant level: MUT includes the Transition Times of all the MSG Configurations being switched.

- Group level:
  - MUT represents the total time that the Multi-Stage Generating Resource must stay within the group. For example, suppose a Multi-Stage Generating Resource has 6 configurations, with configurations 5 and 6 part of a group with a MUT of 6 hours. Once dispatched into either configurations 5 or 6, the resource may transit freely between configuration 5 and 6, but cannot move to a different configuration until the 6 hour MUT has passed. Transition time between MSG configurations within the group is considered as "ON" Time of the group.
  - MDT represents the total time that the Multi-Stage Generating Resource must stay outside of the group. When considering the MDT of a group, the time that the Multi-Stage Generating Resource is operating in a configuration outside the group or within transition outside of the group is considered as the "OFF" time period for the group, in addition to the time that the resource is off line.
- Configuration level: When considering the MDT of a given MSG Configuration, the time that the Multi-Stage Generating Resource is operating on a different configuration or transitioning is considered as the "OFF" time period for the given MSG Configuration, in addition to the time that the resource is off line.

2.1.6 Participating Loads

A Participating Load is an entity providing Curtailable Demand, that has undertaken in writing (by executing a Participating Load Agreement between CAISO and such entity) to comply with all applicable provisions of the CAISO Tariff, as they may be amended from time to time.

From the electrical point-of-view, curtailing Participating Load is analogous to increasing electricity Supply or Generation. Most Participating Loads are Pumping Loads.

Curtailable Demand is Demand from a Participating Load that can be curtailed at the direction of CAISO in the Real-Time Dispatch of the CAISO Controlled Grid. SCs with Curtailable Demand may offer their product to CAISO to meet Non-Spinning Reserve or Imbalance Energy.

There are at least three types of Participating Load: 1) Pumping Load that is associated with a Pump-Storage resource, 2) A single Participating Load (i.e. Pumping and non-Pump Load) that is not associated with a Pump-Storage resource; and 3) Aggregated Participating Load (i.e. aggregated Pumping and non-Pumping Load that is an aggregation of individual loads that operationally must be operating in coordination with each other.

The table below illustrates which of these models are used to accommodate the various types of Participating resources:

Participating Resources	Model Used	Comments
Pump-Storage Resources (i.e. Helms, San Luis)	Pump-Storage Hydro Unit Model	Model can support generation and pump mode. Pump mode is effectively negative generation mode.
Single Participating Load (single Pump and non-Pump Load)	Pump-Storage Hydro Unit Model.	For load (pump-only) the Generation capability of the Pump-Storage model is set to 0 MW. Therefore pump can use negative generation.
Aggregated Participating Load (i.e., aggregated Pumping and non-Pumping Load)	Extended Non-Participating Load Model	Energy will be bid and scheduled using Non-Participating Load in the Day-Ahead Market. To the extent resource is certified to provide Non-Spin, a pseudo-generator model will be used to offer Non-Spin and to the extent necessary dispatch energy from Non-Spin Capacity representing dropping pump load.

CAISO only accepts Bids for a Participating Load from an SC. If the SC is not the entity that operates the Participating Load itself, the SC submits Bids on behalf of the Participating Load for the Supply of Energy or Ancillary Services into the CAISO Markets. All CAISO Markets transactions engaged in by the SC, for a specific Participating Load, are settled with the applicable SC.

Below the following three categories of Participating Load that can participate in CAISO Markets are described further:

- Pumped-Storage Hydro Units

- Single Participating Load (i.e., Pumping load or non-Pumping Load)
- Aggregate Participating Load (i.e. aggregated Pump Load or non-Pumping Load

2.1.6.1 Pumped-Storage Hydro Unit Model

Under this model, the resource looks like a Generating Unit on one side and looks like Load (On or off – single segment) on the other. There are thus three distinct operating modes for a Pumped-Storage Hydro Unit (PSHU) that uses the full functionality of the model. These operating modes are:

- Pumping (i.e., pump on and consuming Energy)
- Offline (i.e., both generation and pump off and not producing or consuming Energy)
- Generating Energy like an ordinary Generating Unit

It is not necessary to utilize all three modes. Some pumps are just pumps in that they only consume Energy, and do not generate Energy. If these pumps wish to participate and sell Imbalance Energy or Non-Spinning Reserves then they must use the same model as the Pumped-Storage Hydro Unit for submission of their Bids into the CAISO Market, but need not enter the Generation side of the model for the optimization. The Generator Bid data of the PSHU model can be left blank. Thus whether a facility is a PSHU or merely a pumping facility the same model is used in the optimization, but with differing levels of Bid data required depending on the functionality being supported.

PSHU can perform either as Generating Unit by supplying Energy or as Loads by consuming Energy from the grid, and therefore they are modeled in the CAISO Markets as Generating Units whose output can go negative when they are functioning as pumps. The PSHU model for Participating Loads models the pumps as Generating Unit with negative Generation capabilities and therefore schedules and settles them at nodal LMPs.

Pumps are modeled with a two-part Bid, namely Shut-Down Costs and Pumping Costs.

1) A Shut Down Cost is an event driven non-Energy based cost that is similar to Start-Up Costs associated with a Generating Unit. The Shut Down Costs represent the costs associated with action of shutting down the pump in dollars per shut-down event. This information is bid in. If the SC does not include any Shut Down Cost component, then the Scheduling Interface and Bidding Rules application (SIBR) inserts a pump Shut Down Cost of $0.

2) Pumping Cost is the hourly cost of operating a hydro pump and it occurs while the pump remains online. In each Trading Day, Pumping Costs are submitted separately for the IFM and the RTM, and may vary by each Trading Hour. Pumping Cost applies only to PSHU and hydro pumps.

3) Pumping Costs are similar in nature to Minimum Load Costs because they are single segment and are represented as a single price for a given Trading Hour for the quantity (MW) of Energy associated with the cost of operating the unit in pumping mode. The pumping operation is restricted to a single operating point, the pumping level, which is submitted with the Bid and can be different in each Trading Hour and across the CAISO Markets. The Pumping Cost is used in the DAM/RTM to optimally schedule the unit in pumping mode. The Pumping Cost represents different things depending on the following:

   a) If the facility is bidding to pump in either DAM or RTM then it represents the Energy Bid Costs the pump is willing to pay in either market, assuming the pump is not already scheduled to consume Energy in that market.

   b) In RTM if the facility has a pumping schedule then the Pumping Costs represent the price at which the pump is willing to be paid to curtail in RTM.

A PSHU facility may submit a Pump Shut Down Cost. If none is submitted, the CAISO will generate these values based on the Master File information. (See BPM for Market Instruments) No shut-down ramp rate is required as it is assumed to be infinite. The PSHU model does not handle Ramp Rates in pumping mode, i.e., the pump starts up / shuts down immediately.

Inter-temporal constraints in pumping mode consist of (1) minimum pumping time (separate from minimum generating time), (2) the maximum pumping Energy per Trading Day, (3) the maximum number of pumping cycles in a Trading Day, (4) minimum lag time between consecutive pump starts in a group[2], and (5) minimum down time. The CAISO minimum down time model will allow for the specification of separate minimum down time values for each of four potential switching sequences:

- Minimum down time when switching from pumping to off to pumping (MDTpp)
- Minimum down time when switching from pumping to off to generation (MDTpg)
- Minimum down time when switching from generation to off to pumping (MDTgp)

[2] See section 6.6.2.2 for more information on grouping constraints.

- Minimum down time when switching from generation to off to generation (MDTgg) (essentially the existing minimum down time feature for generating resources)

In addition, if the PSHU is defined as a group, the following optional features are available:

- A unison operation feature will prevent simultaneous operation of resources in different modes. If selected, the feature will prevent PS resources within a group of resources from being committed in generation mode if any unit within the group is in pumping mode, or vice versa.

- A minimum lag feature specifies the minimum period between the time when the last PS resource in a group is shutdown in pumping mode and the first resource is started in generating mode and vice versa.

An additional feature pertains solely to the PSHU model. In most cases SCs may not submit Demand Bids in RTM because RTM clears Supply against the CAISO Forecast of CAISO Demand. Participating Load using the PSHU model is an exception to this rule in that it can submit Self-Schedules of Demand for Energy in RTM using the same PSHU model method discussed above. The PSHU model does not support aggregation of Participating Load. Rather, to the extent Participating Load makes use of the PSHU model it must represent a single load with a single telemetry and metering scheme.

2.1.6.2 Single Participating Load (Pumping and non-Pumping Load)

Although pumps are bid-in to consume Energy when they are pumping, pumps are modeled as negative Generation in DAM. In DAM an SC may either bid to procure Energy to pump using its Pumping Costs as a substitute of an Energy Bid, or it may Self-Schedule Energy to pump. Each pump is modeled individually. The SC may not submit an Economic Bid to Supply Energy because the generating mode of the PSHU model is not available for a single Participating Load. Furthermore, an SC may not bid to curtail a pump in DAM because in DAM a pump may only have a Pumping Cost or a Self-Schedule to consume Energy. An SC may offer Non-Spinning Reserve capacity in DAM from a pump, but such capacity is only awarded if the pump is scheduled to consume Energy in the DAM. In RTM if an SC wishes to bid to curtail a pump to provide either Energy or Non-Spinning Reserves then it must have a non-zero pumping Schedule from DAM results. If the SC wishes to bid to pump (consume Energy) in RTM it must likewise have a zero pumping Schedule from DAM or a higher pumping level in RTM compared to their pumping schedule in the DAM.

The nature of an SC's schedule as the SC enters a market constrains the options available to facilities. If the SC has a zero pumping Schedule from DAM then obviously it cannot be curtailed to provide Energy in RTM as there is nothing to curtail. If the SC submits a pumping Self-

Schedule or pumping ETC Self-Schedule, the resource will stay in pumping mode and will not be curtailed. Pumping Self-Schedule like any other Self-Schedule is a commitment to be on at minimum load and is effectively fixed. As a result, there is no economic signal available to de-commit the pump. Otherwise the resource will be scheduled optimally to pump or shutdown the pump based on its Pumping Cost and Pump Shut Down Cost.

Pumps can provide two products to the RTM, namely Imbalance Energy and Non-Spinning Reserves, if they enter that market with a non-zero pump Schedule from DAM.

2.1.6.3 Aggregated Participating Load (i.e. Pump and non-Pumping Load)

An Aggregated Participating Load will be modeled and will participate only in the CAISO's DAM as both a Non-Participating Load (NPL) for energy and as a pseudo generating unit for Non-Spinning Reserve through the Extended Non-Participating Load Model. In the first release of MRTU, the Aggregated Participating Load will not be able to participate in the CAISO's markets using a Participating Load model. Rather the Scheduling Coordinator on behalf of the Aggregated Participating Load may submit two Bids for the same Trading Day: (1) using a Non-Participating Load, model a Day-Ahead Self-Schedule with an Energy Bid Curve with a maximum 10 segments; and (2) as a Generator representing the demand reduction capacity of the Aggregated Participating Load, a submission to Self-Provide Non-Spinning Reserve or a Bid to provide Non-Spinning Reserve. The CAISO will assign two Resource IDs: one for Non-Participating Load Bids and one for Generator Bids. Both Resource IDs will be in the Master File on behalf of the Aggregated Participating Load. The Aggregated Participating Load will be treated as a Participating Load for settlement and compliance purposes. As a result the Aggregated Participating Load will be settled at an Aggregate Pricing Node that represents the prices only of those PNodes that make up the Aggregate Participating Load.

2.1.6.4 Non-Pumping Facilities

While most Participating Loads are Pump Loads, There are two ways in which non-pumping Participating Load Resource[3] can participate in the CAISO Markets:

1) To the extent that the non-pumping facility, such as a Demand Response Program (DRP) represents price sensitive Demand that has not executed a Participating Load Agreement, such Demand can be bid to procure at a price, using the ordinary Non-Participating Load Demand Bid in DAM. In this manner the non-pumping facility is represented in the shape of the Demand Bid

[3] Demand Response Programs (DRPs) are one example of non-pumping facilities that can submit Participating Demand bids,

submitted by the SC. This option does not use the PSHU model. If such Demand Response Program is Non-Participating Load, it is settled at the Default Load Aggregation Point (LAP) price.

2) Participating Loads that can model themselves in the same On/Off states as pumps and execute a Participating Load Agreement (PLA), can participate like pumps as described in Section 2.1.4.2. For the non-pumping facilities that represent price sensitive Demand, many of the programs are triggered by specific events such as CAISO declaring a system emergency. If the non-pumping facility Demand is dispatchable in RTM, then the Demand may utilize the PSHU, by responding to Real-Time prices. Non-pumping facilities may bid a similar Pumping Cost into the RTM to either consume Energy in RTM if not already scheduled in DAM or to curtail from the Day-Ahead schedule.

3) Aggregated Participating Loads that represent an aggregation of loads that are not at the same Location and have executed a Participating Load Agreement can submit an Energy Bid Curve, using the non-Participating Load Demand Bid in the DAM and submit a Bid into the Non-Spinning Reserve Market as described in Section 2.1.4.3. Under this model, CAISO adds a pseudo-generator to the CAISO network model to represent the Participating Load, to support bidding and dispatch of Non-Spinning Reserve. For Aggregated Participating Loads, CAISO adds a pseudo System Resource to the network model that allows Energy Bids to be modeled using the same functionality as exports from CAISO.

Attribute	Pump-Storage Model	Extended Non-Participating Load Model
Model	Pump model as negative generator	Load operates as Non-Participating Load. Manual workaround by CAISO allows for participation as Non-Spinning Reserve
Number of Operating Bid Segments	Single segment – Pump is either on or off	Up to 10 segments
Aggregate physical resource?	No	Yes
Bid Component	Two part Bid: ▪ Shut-Down curtailment cost ▪ Pump Energy cost	One part Bid: ▪ Energy Bid curve

Base Load supported	No	No
Settlement	In DAM, Pump can only submit Bid to buy Energy. If scheduled, Pump Load is charged DAM LMP, If not scheduled in DAM, no charge. In RTM, any curtailment from DAM Schedule is paid nodal LMP plus Shut-Down curtailment cost, If Pump is not scheduled in DAM, Pump Load may offer to buy (i.e., to pump) in the RTM	CDWR Participating Loads have separate LAPs for DAM and RTM LMP calculation. For other Participating Loads, CAISO determines feasible level of LMP disaggregation on a case by case basis. DAM Schedule is settled at the DAM LMP. Difference between DAM Schedule and RTM Demand is settled at RTM LMP. Participating Load is not subject to Uninstructed Deviation Penalty.
Treatment in DAM	Modeled as a negative generator. Participating Load may only submit Bid to buy in DAM.	Energy is scheduled in DAM as Non-Participating Load. Participating Load is eligible to submit Bid for Non-Spinning Reserve, using pseudo-generators placed at the locations of the load.
Treatment in RTM	In RTM, Pump may offer to curtail from DAM Schedule (if scheduled in DAM) or offer to buy in RTM (if not scheduled in DAM).	Participating Loads determine RTM operating point by monitoring RTM LMPs. CAISO dispatches Non-Spinning Reserve as contingency only reserve, using pseudo-generators at the locations of the Participating Load. Actual response is expected as a reduction in Demand
Inter-temporal constraints	Yes ▪ Minimum Up Time (minimum time to stay pumping after switching to that mode) ▪ Maximum number of status changes (maximum number of times Pump can switch	No

	from pumping mode) ▪ Daily Energy Limit	
Load Ramping	No	No
Ancillary Service Eligibility	Eligible to provide Non-Spinning Reserve	Eligible to provide Non-Spinning Reserve

2.1.7 Non-Participating Loads

SCs may submit Bids for Non-Participating Loads in DAM to procure Energy. Such Bids may represent an aggregation of Loads and must be bid-in and Scheduled at an Aggregated Pricing Node. Non-Participating Load may not be bid-in to be curtailed in RTM.

2.1.8 Utility Distribution Companies

A Utility Distribution Company (UDC) is an entity that owns a Distribution System for the delivery of Energy, and that provides regulated retail electricity service to Eligible Customers, as well as regulated procurement service to those End-Use Customers who are not yet eligible for direct access, or who choose not to arrange services through an alternate retailer. A UDC has to execute a UDC Operating Agreement with CAISO.

2.1.9 Metered Subsystems

A Metered Subsystem (MSS) is a geographically contiguous electricity system located within an Existing Zone Generation Trading Hub that has been operating as an electric utility for a number of years prior to the CAISO Operations Date as a municipal utility, water district, irrigation district, State agency or Federal power administration, and is subsumed within the CAISO Balancing Authority Area and encompassed by CAISO certified revenue quality meters at each interface point with the CAISO Controlled Grid and CAISO certified revenue quality meters on all Generating Units or, if aggregated, each individual resource and Participating Load internal to the system, that is operated in accordance with an MSS Agreement described in Section 4.9.1 of the CAISO Tariff.

To participate in the CAISO markets, MSSs must be represented by SCs, which can be the MSS itself.

2.1.10 Balancing Authority Areas

The CAISO Balancing Authority Area is one of the Balancing Authority Areas (BAAs) that is under the jurisdiction of the Western Electricity Coordinating Council (WECC). The CAISO Balancing Authority Area is directly connected with the following Balancing Authority Areas. The modeling description is also indicated:

- Bonneville Power Administration (BPA) – external
- PacifiCorp West – external
- Sierra Pacific Power – external
- Nevada Power – external
- Western Area Power Administration-Lower Colorado Region (WAPA-LCR) – external
- Sacramento Municipal Utility District –adjacent
- Arizona Public Service – external
- Salt River Project – external
- Imperial Irrigation District – external (candidate adjacent in future)
- Los Angeles Department of Water & Power – external (candidate adjacent in future)
- Comision Federal De Electricidad – external (candidate adjacent in future)
- Turlock Irrigation District – adjacent

In addition to the modeling of the CAISO Balancing Authority Area, there are three types of Balancing Authority Area modeling designations as briefly discussed below and further explained in the *BPM for Managing Full Network Model* :

- **External** – External Balancing Authority Areas are generally modeled in detail by using the same model for the EMS State Estimator and the CAISO Markets, including where New Participating Transmission Owners (PTOs) have converted their Existing Rights to the CAISO Controlled Grid,[4] and Integrated Balancing Authority Areas. For external Balancing Authority Areas, imports and exports are modeled as injections at Scheduling Points in the detailed external network model, at tie points where Transmission Interfaces are interconnected, and in which Real-Time power flows developed in the State Estimator account for unscheduled as well as scheduled power flows. The CAISO models the resistive component for transmission losses in external Balancing Authority Areas but does not allow such losses to determine LMPs, since these losses are settled by the external Balancing Authority Areas.

[4] The New PTOs' Converted Rights are in portions of the Los Angeles Dept. of Water and Power, Western Area Power Administration Lower Colorado, Arizona Public Service, PacifiCorp East, and Sierra Pacific Control Areas.

- **New PTO Model**: For the CAISO Controlled Grid that is comprised of the New PTO's Converted Rights, the network model includes physical branches within external Balancing Authority Areas, and enforces the limits of the Existing Rights.

- **Integrated Balancing Authority Areas –** For external Balancing Authority Areas where there is sufficient data available or adequate estimates can be made for an IBAA, the FNM used by the CAISO for the CAISO Markets Processes will include a model of the IBAA's network topology. The CAISO monitors but does not enforce the network Constraints for an IBAA in running the CAISO Markets Processes. Similarly, the CAISO models the resistive component for transmission losses on an IBAA but does not allow such losses to determine LMPs that apply for pricing transactions to and from an IBAA and the CAISO Balancing Authority Area, unless allowed under a Market Efficiency Enhancement Agreement. For Bids and Schedules between the CAISO Balancing Authority Area and the IBAA, the CAISO will model the associated sources and sinks that are external to the CAISO Balancing Authority Area using individual or aggregated injections and withdrawals at locations in the FNM that allow the impact of such injections and withdrawals on the CAISO Balancing Authority Area to be reflected in the CAISO Markets Processes as accurately as possible given the information available to the CAISO.

The CAISO has executed a number of Interconnected Balancing Authority Areas Operating Agreements with interconnected Balancing Authority Areas to establish the relationship between CAISO and the neighboring Balancing Authority Area. Balancing Authority Areas that are eligible to participate in the CAISO Markets must do so through an SC (which can be the same entity).

2.1.11 Participating Transmission Owners

A Participating Transmission Owner (PTO) is a party to the Transmission Control Agreement whose application under Section 2.2 of the Transmission Control Agreement has been accepted and who has placed its transmission lines and associated facilities, and Encumbrances under CAISO's Operational Control in accordance with the Transmission Control Agreement between CAISO and such PTO.

There are two types of Participating Transmission Owners:

- **Original** Participating TO – PTOs as of December 31, 2000
- **New** Participating TO – PTOs since January 1, 2001

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)
- 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.

2.1.14 Pseudo-Tie

A Pseudo-Tie is a single resource physically located outside of the CAISO Balancing Authority Area, but contractually part of the CAISO Balancing Authority Area for purposes of production, ancillary services responsibility, operating jurisdiction, etc. Unless otherwise noted, Pseudo-Tie Generators are modeled and treated by the market similar to Generating Resources.

2.1.15 Use-Limited Resources

Scheduling Coordinators (SCs) may register and qualify their resources as Use-Limited Resources pursuant to the requirements specified in Section 30.4.6.1 of the CAISO Tariff. To initiate the process, the SC should submit a request to register use limitations via CIDI with the subject 'Use-Limited Registration'. The CAISO will validate if the use limitations the SC is requesting to register in the Use Limit Plan Data Template (ULPDT) meet the use-limitation criteria in section 30.4.6.1. If CAISO approves any submitted limitation to be registered, the CAISO will designate resources as Use-Limited Resources in Master File Generator Resource Data Template associated with the approved use limitation. Resources registered as Use-Limited are excluded from utilizing the Aggregated Capability Constraint per section 27.13 of the CAISO Tariff.

For the CAISO to designate a resource as Use Limited, the CAISO and SCs must perform two steps:

4) the CAISO must approve at least one qualifying limitation in the use limitation registration process (approved limitations) for the resource to qualify as a Use-Limited Resource.

5) the SC must register approved limitations in the ULPDT.

For the first step, the SC must provide sufficient documentation to support the SC is eligible to register the use limitation in the ULPDT based on meeting all three criteria defined in Section 30.4.6.1. The approved use limitation(s) will be defined as the unique combination of use limit type, granularity, effective start date, effective end date, and whether the limitation values are fixed or dynamic. For fixed limitation values, the qualifying limitation values are registered as fixed values where the explicit value is validated in the registration process. For dynamic limitation values, the qualifying limitation values are registered as dynamic values where the methodology used by the SC to determine the limitation value is validated in the registration process.

For a use limitation to qualify, the limitation must meet all three criteria of Section 30.4.6.1 and must be able to be rationed in response to CAISO energy price signals over the registered granularity. The criteria are:

1) There is a limitation on the resource number of starts, run-hours, or energy output due to design considerations or environmental restrictions.

2) The resource limitation cannot be reflected within the market optimization horizon (e.g. monthly limitations that extend beyond the day-ahead market 24 hour horizon).

3) The resource's ability to select hours of operation is not dependent on an energy source outside of the resource's control being available during such hours but the resource's usage needs to be rationed.

The following capacity will not be eligible to request consideration of use limitations since the Resources are not subject to opportunity costs. These resource types are not subject to opportunity costs because they do not have the ability to select the hours or energy output levels that can be provided to CAISO market:

- Variable Energy Resources
- Regulatory Must Take
- Reliability Demand Response Resources

For the second step, the SC must register only the approved values as defined in the registration process in the ULPDT. See Attachment B of the Market Instruments BPM for instructions on registering the approved limitations in Master File. Based on the approved limitations, the CAISO will designate the resource or Multi-Stage Generator as a Use-Limited Resource (details in Section 2.1.15.3).

Use-Limited Resource designation results in the following CAISO processes or procedures being available to the SC to manage these resources:

- Exempts Resource Adequacy Capacity of a Use-Limited Resource from bid generation under Section 40.6.8(e).
- Access to the Annual Use Limit Reached, Monthly Use Limit Reached, Other Use Limit Reached, Short Term Use Limit Reached nature of work outage cards. See the Outage Management BPM for more information on the definition of the nature of works and the Reliability Requirements BPM for more information on the substitution requirements and

resulting Resource Adequacy Availability Incentive Mechanism (RAAIM) exposure for each nature of work outage card.

- Ability to seek to establish an opportunity cost adder[5] to its Default Start-up Bid, Default Transition Bid, Default Minimum Load Bid (i.e. its start-up, transition, minimum load bid caps) or to a generated energy bid or default energy bid, with the exception of use limitations with a daily granularity.

2.1.15.1 Request to Register Use Limitations

To register a use limitation, the SC should open an Inquiry Ticket via the Customer Inquiry Dispute and Information (CIDI) tool with the subject**,** "Use-Limited Registration". The CIDI Ticket should include specific operating data for the unit and supporting documentation similar to those described above. The inquiry ticket should include, but not be limited to:

- ULPDT with records for qualifying use limitations under Section 30.4.6.1. See Attachment B of the BPM for Market Instruments for more information about the ULPDT.
- A detailed explanation of why the resource is subject to the qualifying use limitations.
- Documentation, such as environmental permits or operating manuals, as well as page numbers or section numbers in the supporting documentation, substantiating the detailed explanation of why the unit is subject to use limitations.
- Calculations that describe the methodology, including input values and formulas where possible, to translate limitations into the use limit types, granularity, and limitation values submitted in the ULPDT. If a formulaic translation cannot be provided, provide a detailed explanation of how the type, granularity, and limitation value was translated based on supporting documentation including page numbers or section numbers in the supporting documentation.
- If limitation type cannot be translated into a standard use limit type of 'START', 'RUNHOURS', or 'ENERGY', a detailed explanation of why the limitation could not be translated.

[5] See Attachment N of the Business Practice Manual for Market Instruments for more information.

- If limitation granularity cannot be translated into a standard use limit type of ‘MONTHLY, ‘ANNUALLY’, or ‘ROLL_12’, a detailed explanation of why the limitation could not be translated.

- Explanation stating whether the resource’s operation is dependent on an energy source outside of the resource’s control being available during select hours. For example, SOLAR, WIND, WATER, and GEOTHERMAL resources that are dependent on intermittent energy sources will need to provide detailed explanation of the design features that allow it to operate in any hour similar to resources with prime movers not based on intermittent energy resources.

- Explanation stating whether the resource has available fuel or fuel-equivalent (i.e. water) available across the granularity of the limitation to allow it to participate economically in the CAISO market.

- Any additional data in order for CAISO to understand the operating characteristics of the unit.

If multiple resources are subject to a use limitation based on the same supporting documentation, the SC should submit a single CIDI ticket for the use limit plan and its supporting documentation and provide a list of all resources that are limited based on the attached documentation. SC should attach the ULPDT with records for each resource or configuration limited based on the attached documentation. For example, where a Demand Response Provider has contracted with a LSE to participate in a demand response program where it has multiple Proxy Demand Response (PDR) providers under the same LSE DR program, should submit a CIDI request for Use-Limited Resource status for resources under the LSE DR program, attach the DR program documents, and submit ULPDT with records for each resources under that LSE DR program. Additional examples are provided in the next section.

If the supporting documentation does not explicitly state the use limitation as either a ‘START’, ‘RUNHOUR’, or ‘ENERGY’ limit type, the SC should attempt to translate the limitation based on the documentation into either the ‘START’, ‘RUNHOUR’, or ‘ENERGY’. If the supporting documentation does not explicitly state the granularity as either ‘DAILY’, ‘MONTHLY’, ‘ANNUAL’, or ‘ROLL_12’ granularity, the SC should attempt to translate the limitation based on the documentation into either the ‘DAILY’, ‘MONTHLY’, ‘ANNUAL’, or ‘ROLL_12’. The SC should submit a written explanation of this translation methodology including formulas so the CAISO can validate the submitted ULPDT against the supporting documentation.

If the SC cannot translate the non-standard limitation type or granularity, then the SC should register in the appropriate field the ‘OTHER’ value. The CAISO will notify the SC of the need to

enter a consultation with the CAISO to determine the USE LIMIT TYPE, GRANULARITY, PLAN STRT DT TM, PLAN END DT TM, and methodology for determining the LIMITATION values. The consultation is based on what translation methodology will best allow the CAISO to respect the use limitations of these resources. Following the consultation, the CAISO will provide the SC a written report based on the consultation for use in a revised use limitation registration request via CIDI.

The following sections will discuss in more detail specific instructions for submitting supporting documentation for the request based on a non-exhaustive list of potential use limitations.

2.1.15.1.1 Emission Limitations

SC may seek to register use limitations in the ULPDT based on emission limitations from air permit restrictions that are imposed on the operations of the unit on a 24-hour or longer applicability horizon. The daily start limitations will only be accepted for resources with a cold start-up time of 300 minutes or less because otherwise the resource is a long start resource that only receives binding start-up instructions in the day-ahead market where the daily limitation can be recognized in the day-ahead optimization horizon.

The CAISO observes that many air permits impose operational conditions on the units not to exceed a certain number of fired starts or fired engine hours of operation by the turbine or for the combined turbines of the plant. The SC should register its limitation and granularity based on the specified number of engine starts or run hours listed in the air permit. The SC should provide, in its supporting documentation, the section and page number where the specified operation condition per granularity is listed. For example, if the permit provides a limitation on the number of run hours per turbine per year, then the MSG resource would need to register an MSG configuration-level limitation in the ULPDT along with the corresponding implied starts associated with each configuration in the GRDT. If the permit provides a limitation on the number of hours of operation for all the configurations, the MSG resource would register a MSG plant-level limitation on the run hours with the applicable granularity.

The CAISO also observes that the air permit may differentiate between the limitation on run hours during start-ups and/or limitation on run hours from start-up through its run time and shut-down. The SC can request multiple use limit types based on the limitations documented in the permit. For the former, a limitation on the run hours during start-up, the SC may be able to translate this to a limitation on the number of starts. For the latter, a resource with a limitation on the number of run hours from start-up through its run time, the SC will register this as a limitation on the number of run hours of the resource. The SC should document the section and page number of the air permit page where the limitation is documented along with applicable documentation supporting the translation to the limitation requested in the ULPDT.

While less common, the CAISO understands that some air permits may not explicitly state the operational condition on starts, run hours, or energy output in order to provide more flexibility to the plant operator. In that event, the CAISO anticipates the air permit would explicitly list the pollutants and emission limits that the resource is subject to and over what period of time along with a limitation on the heat input of the plant based on MMBtu per day and per year. The SC should submit an Excel document that shows the emission limitations, heat input limitations, and the proposed methodology for translating the heat input limitations into 'START', 'RUNHOURS' or 'OUTPUT' limitation. The CAISO may ask for additional information such as capacity factor of the unit and the SC's expectations of emission rates at various operating levels efficiency (e.g. heat rates). The limitation methodology may translate the emission limitations into starts, run-hours, or energy based on likely use of the plant and the operational use needing to be better optimized.

For resources with fuel-switching capabilities where the limitations may differentiate between multiple modes of operation, the SC should register the limitation for the operating mode that provides more operational flexibility if it does not want to enter into a negotiation for opportunity costs. The more complex nature of multiple operating modes being subject to multiple limitations on the same use limit type that is conditional on type of mode may be more appropriate to be determined through a negotiation. The SC could register the complex limitation of its resource as 'OTHER' if it wants to be considered for negotiations and document the reason as multiple operating modes with different use limitations depending on its use of that mode.

2.1.15.1.2 Storage capability limitations – Non-Hydro

Non-hydro resources seeking Use-Limited Resource status based on limited storage capability that can be supported by design documentation should submit the design documentation to the registration request. The SC should attach a translation methodology for translating the storage capability into start, run-hours, or energy output limitations and specify its storage inventory levels that it needs to maintain in its storage inventory based on external obligations such as providing reliability needs during peak conditions. If SC is unable to provide a translation methodology into start, run hour, or energy output, they should designate the USE LIMIT TYPE as 'OTHER' in the attached ULPDT.

2.1.15.1.3 Storage capability limitations – Hydro

To be eligible for use limitation registrations, hydro resources must be subject to use limitations for energy, hours, or starts it can provide during the period it is subject to a use limitation.

The granularity (e.g. the month, the year) that the use limitation is available for should be the period where the first day the entire limitation is available based on projections of inflows and

outflows during the period where the acre-feet of water is being managed to meet minimum reservoir targets. As the inflows and outflows during the period actualize, the CAISO expects the SC to resubmit the ULPDT with the revised values given actual data or more timely projections. The projected outflows include all the releases to manage minimum flow requirements, synchronize flow rates upstream and downstream, water deliveries, etc.

The amount available on the first day of the granularity is the excess amount of water above that reserved for water operations that can be converted into MWh and either released for energy production or reserved for later use based on the CAISO price signals. The CAISO is asking each SC to provide their methodology for translating the water available for electric generation outside of other water operations.

For example, if resource is subject to a two-year limitation, the granularity would be 'OTHER' and the effective plan start and end dates would capture the two consecutive years. CAISO would assume the hydro two-year limitation is two consecutive water years. The limitation value would be the projected MWh available for dispatch in CAISO market across the two-year period in response to CAISO price signals – outside of outages and not accounting for energy production that is a byproduct of water operations. The initial value registered could be current elevation (TAF) plus projected inflows, minus projected outflows needed to meet water use requirements and/or water deliveries, minus the reserve margin needed to hedge risk for dry periods, and minus the minimum reservoir target. The SC can update the value subject to a five-business day processing time as information on inflows and outflows change.

Potential granularities for limited storage capacity limitations:

- If operational requirements prescribe when the water flows including releases for water use or operations to manage flow rates upstream and downstream, these are treated in the CAISO market as operational requirements not use limitations that have an opportunity cost in the CAISO market.

- If operational requirements allow for MWh production in response to CAISO price signals across the 24-hour period as long as the MWh daily energy limit is respected, the hydro resource limitation would be registered as a 'DAILY' limitation.

- If operational requirements allow for MWh production in response to CAISO price signals across period greater than 24 hours but less than a month as long as the MWh energy limit is respected, the hydro resource limitation would be registered as an 'OTHER' limitation. The effective date range should match the granularity of the 'OTHER' period.

- If operational requirements allow for MWh production in response to CAISO price signals across period of a month as long as the MWh energy limit is respected, the hydro resource limitation would be registered as a 'MONTHLY' limitation.

- If operational requirements allow for MWh production in response to CAISO price signals across period greater than a month but less than a year as long as the MWh energy limit is respected, the hydro resource limitation would be registered as an 'OTHER' limitation. The effective date range should match the granularity of the 'OTHER' period.

- If operational requirements allow for MWh production in response to CAISO price signals across period of a year as long as the MWh energy limit is respected, the hydro resource limitation would be registered as an 'ANNUALLY' limitation.

- If operational requirements allow for MWh production in response to CAISO price signals across period greater than a year as long as the MWh energy limit is respected, the hydro resource limitation would be registered as an 'OTHER' limitation. The effective date range should match the granularity of the 'OTHER' period.

- In certain circumstances, the SC and the CAISO may agree to convert the 'OTHER' limitations to 'MONTHLY' or 'ANNUALLY' limitations in order to facilitate the calculations of opportunity costs.

2.1.15.1.4 Technical Standards Operating Limits

Resources may seek to register use limitations based on submitting a technical standard for that technology's operation (e.g. IEEE/ANSI C50.10-1977 - American National Standard General Requirements for Synchronous Machines). The SC should provide the technology-specific standard, OEM recommendation containing the lifecycle of the plant, and the template that translates the lifecycle limitation on starts and/or run-hours into an available annual/monthly start and/or run-hour limitation(s).

The CAISO expects the standard will establish either a number of starts or number of run-hours across the lifecycle of the unit or it will further refine the lifecycle limitation by an annual limitation. The annual limitation would be more limiting and would effectively ration the lifecycle uses so the SC should establish the limitation at the annual value. If the standard establishes a lifecycle limitation, the SC will be required to translate the lifecycle limitation into an annual limitation by dividing the remaining available uses out of the lifecycle limitation into annual profiles.

For example, if the standard says that the technology should be limited to 50,000 run-hours across the 30-year lifecycle of the unit based on OEM recommendation, and the unit has

already operated for 20,000 run-hours and is 15 years old, then the available use is 30,000 run-hours across the remaining 15 years of the lifecycle. The CAISO will require the SC to register the limitation assuming that the SC pro-rated the use equally across the remainder of the lifecycle. For this resource this would be 2000 run-hours on an annual granularity (=30,000 run-hours available/15 years remaining). If the standard says that a synchronous machine should not start more than 10,000 starts for its lifecycle and no more than 500 starts per year, the SC would register the design-based limitation at 500 starts per year.

2.1.15.1.5 Battery Storage Warranty Limitations

Resources that have use limitations because of battery storage warranties can request to register the storage limitations (e.g. Proxy Demand Response Resources, Limited Energy Storage Resource). Any documentation that reflects an externally imposed limitation based on either design or regulatory restrictions (per Tariff) will be reviewed and evaluated for meeting the criteria. The CAISO will validate the limitations meet all three criteria of Section 30.4.6.1.

The SC should submit a request with an attached ULPDT that includes a record for the limitation that specifies the use limit type, granularity, effective dates, and limitation amount and attach the supporting documentation. The SC should identify in its submission the section and page of the supporting documentation that includes the details for the use limitation.

2.1.15.1.6 Demand Response Program Limitations

Proxy Demand Response (PDR) resources should submit requests to be registered as Use-Limited Resources based on their California Public Utility Commission demand response program contracts to be eligible for CAISO processes or procedures available to Use-Limited Resources. PDR resources may register the use limitations based on their program limitations. Demand Response Resources include both load curtailment and storage-backed demand response providers.

PDR resources have design limitations due to programmatic limitations that refer to the maximum events or hours per a deliverability period for which customers are expected to be willing to curtail or deploy state of charge when called upon. For each PDR resource, the SC should identify the name of the entity that is the Load Serving Entity or Electric Service Providers and Community Choice Aggregators acting as the Load Serving Entity [DR Buyer] that the PDR is under contract with, the name of the demand response program, the associated program description, and the contracts.

The SC should attach to submission:

- ULPDT to include each use limitation under a participating program.

- Spreadsheet that details the name of the entity that is the Load Serving Entity or Electric Service Providers and Community Choice Aggregators acting as the Load Serving Entity [DR Buyer] that the DR is under contract with, the name of the demand response program, contract name, and the resource ID.

- Demand Response Program Documents and Description

- Demand Response Program Contracts

2.1.15.1.7 End-of-Life Resources

In the event that a particular resource is nearing the end of its useful life, cannot perform further maintenance to avoid a retirement or repowering, and the resource is needed by the CAISO for reliability purposes and does not otherwise meet the criteria set forth in section 2.1.15.1.4, the CAISO may designate that resource as Use Limited. The CAISO expects that the resource's limitation would be calculated consistent with section 2.1.15.1.4 but, instead relying on the technical standard for the number of starts, run-hours, or MWh remaining in the lifecycle of the unit, the CAISO would rely on the plant engineer's reasonable estimate. The CAISO expects that the SC would provide their estimate of the resource's limitation supported by plant engineering estimates when submitting its ULPDT. The CAISO expects that use limitations registered under this section would be annual and monthly limitations calculated based on the remaining years of the resource's useful life. The CAISO would review these and, if necessary, ask questions of the SC about the underlying assumptions or limitation value. Resources registered under this option cannot use the Annual Use Limit Reached, Monthly Use Limit Reached, Other Use Limit Reached, Short Term Use Limit Reached nature of work outage cards.

2.1.15.1.8 Reliability Must-Run Resources

Normal, Non-Legacy Reliability Must-Run (RMR) resources may also register use limitations under section 30.4.6.1. In addition, RMR resources may also register use limits to manage the timing of a major outage. This special RMR use limitation is codified in an executed Reliability Must-Run contract. A Pro-Forma RMR contract can be found in Appendix G of the CAISO Tariff. The Pro-Forma RMR contract explains that use limitations can be created based on the "Remaining Start-ups, Run hours, MWhs prior to Need for Capital Item" and that "these limits will be considered as eligible limits for development of appropriate opportunity costs." If an RMR resource is facing such a limitation, they should complete a ULPDT as explained in Attachment B of the BPM for Market Instruments noting that they are an RMR resource and the use-limitation is being registered under an executed RMR contract. The CAISO will process these according to the standard use-limitation registration process.

2.1.15.2 Validating Use Limitations

The CAISO will respond to the SC initially to confirm receipt of the use limit status request and pending completion of the validation of the use limit plan.

Per Section 30.4.6.1, SCs are ineligible to register any use limitation that does not meet all three criteria for a qualifying limitation with an opportunity cost. Use limitations are eligible for registering a ULPDT in Master File if:

- The SC provides sufficient supporting documentation to show that the resource is subject to use limitations that affect the number of starts, run-hours, or energy output due to design considerations, environmental restrictions, or qualifying contractual limitations.

- The CAISO market process cannot capture the limitation. If the market process can capture the limitation through economic bids, self-schedules, or outages then this is considered an operational limitation that can be captured by the market process. For example, if a resource cannot control its output because of other operational constraints and need to limit its capacity, the resource can reflect this in the market through submitting an outage card.

- The resource's ability to select hours of operation is not dependent on an energy source outside of the resource's control being available during such hours but the resource's usage needs to be rationed.

- For start limitations, the granularity of the limitation should be shorter than the resource's appropriate commitment process in CAISO market. For example, an extremely long start or long start resource (highest startup time registered is greater than 300 minutes), that has use limitations on starts that apply on a daily granularity will not be eligible to

register the use limitation since this resource can only be committed in the day-ahead market which can support daily start limitations.

The following table includes a non-exhaustive list of limitations and the expected CAISO determination for each category. The first column, Limitation Category, describes the type of limitation that the CAISO anticipates a SC may try to register as a use limitation under Section 30.4.6.1 of the Tariff. The second through fourth columns represent the three criteria that should be met for the CAISO to validate a limitation qualifies as a use limitation. For each limitation category, columns two through four show a 'Y' or 'N' if the CAISO expects to validate that category meets or does not meet each criterion respectively. The final column, Limitation Outcome, shows 'Accepted' if all three criteria are met where columns two through four show a 'Y'. Otherwise, the Limitation Outcome is 'Rejected' when any criterion is not met.

Limitation Category	**Tariff Section 30.4.6.1 Criterion (1)**	**Tariff Section 30.4.6.1 Criterion (2)**	**Tariff Section 30.4.6.1 Criterion (3)**	**Limitation Outcome**
Emission Limitation (Air District) - Less than daily limit	Y	N	Y	Rejected
Emission Limitation (Air District) - Daily limit or greater	Y	Y	Y	Accepted
Emission Limitation (Air District) - Daily limit or greater - cannot control output due to other operating requirements.	Y	Y	N	Rejected
Firm delivery of power or natural gas at resource location limited under long-term agreement where the underlying limitation is an infrastructure limitation in storage or transport capability combined with need to manage resources to meet CAISO needs and other customers.	Y	Y	Y	Accepted
Storage flexibility to maximize economics of power production for period greater than 24 hours: Energy production largely not dependent on a prime mover outside of its control due to intermittency, energy	Y	Y	Y	Accepted

Limitation Category	Tariff Section 30.4.6.1 Criterion (1)	Tariff Section 30.4.6.1 Criterion (2)	Tariff Section 30.4.6.1 Criterion (3)	Limitation Outcome
deliverability, or water requirements. Amount of stored fuel, energy, or water is available to maximize economic value of generation for more than 24 hours in addition to other requirements (reliability, native load, or water use).				
Storage flexibility to maximize economics of energy production for period of 24 hours: Energy production is largely but not completely dependent on prime mover outside of its control due to intermittency, energy deliverability, or water requirements. Amount of stored fuel, energy, or water is available to maximize economic value of generation over 24 hours in addition to managing other requirements (reliability, native load, or water use).	Y	Y	Y	Accepted
Storage flexibility to maximize economics of ancillary service provision for period greater than 24 hours while selecting hours to operate in energy market: Energy production dependent on prime mover outside of its control due to intermittency, energy deliverability, or water requirements. Amount of stored fuel, energy, or water is available to maximize economic value of ancillary service provision on top of self-scheduled energy capacity when made available.	Y	Y	N	Rejected

Limitation Category	Tariff Section 30.4.6.1 Criterion (1)	Tariff Section 30.4.6.1 Criterion (2)	Tariff Section 30.4.6.1 Criterion (3)	Limitation Outcome
Storage flexibility to maximize economics of ancillary service provision for period of 24 hours while selecting hours to operate in energy market: Energy production dependent on prime mover outside of its control due to intermittency, energy deliverability, or water requirements. Amount of stored fuel, energy, or water is available to maximize economic value of ancillary service provision on top of self-scheduled energy capacity when made available.	Y	Y	N	Rejected
No storage flexibility to maximize economics of energy production instead limited to selecting hours to operate: Energy production dependent on prime mover outside of its control due to intermittency, energy deliverability, or water requirements. Not able to maximize economic value of generation so must select hours to operate within 24-hour period.	Y	N	N	Rejected
Resource subject to conditional use permit from an external entity that restricts number of uses across extended period where resource is agnostic to which hours within that period are dispatched.	Y	Y	Y	Accepted
Resource subject to conditional use permit from an external entity that restricts number of uses during specific periods.	Y	N	N	Rejected

Limitation Category	Tariff Section 30.4.6.1 Criterion (1)	Tariff Section 30.4.6.1 Criterion (2)	Tariff Section 30.4.6.1 Criterion (3)	Limitation Outcome
Resources subject to operating constraints where the resource does not have the ability to select the hours to operate and instead must self-schedule or submit outages to reflect the inflexibility of the operating constraint.	Y	N	N	Rejected
Combined Heat & Power Plant (i.e. Cogeneration) that economically participates in CAISO energy market that has restrictions on starts, run-hours, or energy as result of design, environmental, or contract limitations over extended period (across 24 hours or more). Because the Combined Heat & Power Plant energy production is not fully subject to upstream process, where energy production is not fully dependent on the CHP operations and resource is responsive to energy price signals.	Y	Y	Y	Accepted
Combined Heat & Power Plant (i.e. Cogeneration) that cannot economically participate in CAISO energy market even if it has restrictions on starts, run-hours, or energy as result of design, environmental, or contract limitations over extended period (across 24 hours or more). Because the Combined Heat & Power Plant energy production is subject to upstream process where energy production is dependent on the CHP operations and non-responsive to energy price signals.	Y	N	N	Rejected

Limitation Category	Tariff Section 30.4.6.1 Criterion (1)	Tariff Section 30.4.6.1 Criterion (2)	Tariff Section 30.4.6.1 Criterion (3)	Limitation Outcome
Participating Generator Agreement Limitation Schedule	N	Y	Y	Rejected
Variable Energy, Regulatory Must Take, Reliability Demand Response Resources	Y	N	N	Rejected
Contract limit explicitly stated in contract filed at LRA	N	Y	Y	Rejected

2.1.15.3 Designating Use-Limited Resources

If the CAISO was unable to validate a use limitation submitted in the use-limited registration process met all three criteria, the CAISO will not designate the resource as a Use-Limited Resource. The CAISO will notify the SC the resource is ineligible for use limit status.

If the CAISO was able to validate a use limitation submitted in the use-limited registration process met all three criteria, the CAISO will designate the resource as a Use-Limited Resource. The CAISO will set the GRDT USE_LIMIT flag to 'Y' and notify the SC of the effective date in Master File. As soon as the USE_LIMIT flag is set to 'Y' in Master File GRDT, the SC can update the ULPDT into the Upload tab of the Master File portal with the CIDI Ticket number in the batch comment field. See Attachment B.6 of the Market Instruments BPM ULPDT for instructions on updating the Master File ULPDT.

2.1.15.4 Maintaining Use-Limited Resource Designation

SCs for Use-Limited Resources are required to submit a use limitation registration renewal request each year by November 1st to maintain their Use-Limited Resource status designation. The renewal will be for 24 months for rolling 12 limitations and 12 months for all other limitation granularities. If the SC does not submit the renewal request for the Use Limitation Registration, then the CAISO will remove the resource's Use-Limited Resource Designation.

To maintain the designation, the SC must submit via CIDI use limitation registration renewal request no later than November 1st to ensure it can maintain an active limitation record in the ULPDT[6]. If the approved limitation was previously registered and its supporting documentation did not change, the SC can submit with its annual registration renewal request for future years a statement in the CIDI case attesting that the use limitation(s) and all supporting documentation have not changed.

Alternatively, if the limitation definition has changed based on changes to supporting documentation or a desired change to the translation methodology used, the SC must submit a new use limitation registration request to register the new use limitations. The CAISO considers a use limitation to have changed if the use limit type, granularity, or fixed values or dynamic methodology changes.

If there is an active ULPDT record associated with a resource ID, the CAISO will maintain the Use-Limited Resource status designation in Master File Resource Data Template as Use-Limited. If there is no longer an active ULPDT record associated with a resource ID, the CAISO will set the Use-Limited Resource status designation in Master File Resource Data Template to not Use-Limited.

2.1.15.5 Multi-Stage Generator with Registered Start Limitations

The IMPLIED_STRTS fields contained in the MSG_CONFIG tab of the Generator Resource Data Template (GRDT) is for Multi-Stage Generator (MSG) resources with start limitations to register the number of starts associated with moving a resource from offline to online or from online to a higher configuration that is implied by the use limitation plan's supporting documentation. The DOC_NAME including the CIDI ticket number for the approved ULPDT will provide support for the values registered in these fields. The implied starts is only for the Opportunity Cost Calculation to account for starts on an MSG and will not be used in any other market optimization.

Only Use-Limited MSG resources with start limitation(s) can have implied starts greater than 1. Implied starts for non-MSG resources are assumed to be one. The number of implied starts for an MSG configuration shall be measured from the MSG resource being entirely off to being started directly to that configuration. MSG resources have to include an implied start value in the MSG_CONFIG tab of the GRDT for every configuration of the MSG resource. An implied start for the configuration can be set to zero for a configuration.

[6] Attachment B.6 Use Limit Plan Data Template.

For MSG resources that submit use limitations that are for use limit types of 'RUNHOURS', 'ENERGY', or 'OTHER', the SC should not submit values in the IMPLIED_STRTS field. The IMPLIED_STRTS field will be defaulted to NULL in the GRDT.

For MSG resources, the limitation on the number of starts in the use limitation plan is the number of implied starts to be determined based on the supporting documentation for the use limitation request. The supporting documentation provided during the use-limit registration process should describe how the plan implies that a usage of its start limitation should be measured. Each implied start will contribute to the usage of the start limitation on file in the ULPDT in the 'LIMITATION' field. Implied starts registered in the GRDT should be the same resolution level on which the MSG configuration will submit the use-limit limitation of number of starts. The following examples will explain to what "resolution level" refers.

The following table shows the likely scenarios of use plan limitations, and consequently how to register the implied starts for each of these scenarios. The first column, 'Scenario', shows a short name for the next column describing the 'Use Plan Limitation Type.' If the MSG resource's limitations fall under these implied start types, the SC should register the IMPLIED_STRTS in the MSG_CONFIG tab of the GRDT as shown in the examples. The transition implied starts will be derived by the CAISO from the implied starts registered for each MSG configuration, implied start values must be based on the type of use limitation and supporting documentation.

Scenario	Use Plan Limitation Type
PLANT_A	– Plant level[7] limitation that does not consider a transition a "start" where each start=1. – ULPDT limitation registered at MSG resource level not configuration level. – Supporting documentation considers CAISO startup commitment of any configuration in the plant a use of the limit. – SC registers IMPLIED_STRT for each configuration as 1. – Transition IMPLIED_STRT will be derived as the difference between IMPLIED_STRT of 'To Configuration' and IMPLIED_STRT

[7] Non-MSG resources, resource level limitations and MSG resources plant-level limitations are treated similarly. A MSG resource level limitation is the same as a MSG plant-level limitation.

Scenario	Use Plan Limitation Type
	of 'From Configuration'. Derived transition IMPLIED_STRT should be equal to 0 for this limitation type.
PLANT_B	– Plant level limitation that does not consider a transition a "start" where each start=number of engine (e.g., CT) starts. – ULPDT limitation registered at MSG resource level not configuration level. – Supporting documentation considers fired turbine starts from offline a use of the limit. – SC registers IMPLIED_STRT for each configuration as the number of fired turbines associated with starting up the configuration from offline to that configuration. – Transition IMPLIED_STRT will be derived as the difference between IMPLIED_STRT of 'To Configuration' and IMPLIED_STRT of 'From Configuration'. The derived transition implied start will not be equal to the transition implied starts appropriate for this type of limitation (derived transition IMPLIED_STRT = 0). – Functionality does not support ability to model opportunity cost for this type of plant level limitation. SC needs to identify the derived transitions are not compatible with plan. The CAISO will negotiate an opportunity cost adder.
PLANT_C	– Plant level limitation that does consider a transition a "start" where each start or transition=number of CT starts. – ULPDT limitation registered at MSG resource level not configuration level. – Supporting documentation considers starts or transitions (fired turbines) a use of the limit. – SC registers IMPLIED_STRT for each configuration as the fired turbines associated with starting up the configuration from offline to

Scenario	Use Plan Limitation Type
	that configuration. – Transition IMPLIED_STRT will be derived as the difference between IMPLIED_STRT of 'To Configuration' and IMPLIED_STRT of 'From Configuration'.
CONFIG_A	– Configuration level limitation that does consider a transition a "start" where each start or transition=number of CT starts. – ULPDT limitation registered at MSG configuration level not plant level. – Supporting documentation considers starts or transitions (fired turbines) a use of the limit. – SC registers IMPLIED_STRT for each configuration as the fired turbines associated with starting up the configuration from offline to that configuration. – Transition IMPLIED_STRT will be derived as the difference between IMPLIED_STRT of 'To Configuration' and IMPLIED_STRT of 'From Configuration'.
CONFIG_B	– Configuration level limitation that does consider a transition a "start" where each start or transition=1 (E.G. C3 Limitation). – ULPDT limitation registered at MSG configuration level not plant level. – Supporting documentation considers CAISO startup commitment or CAISO transition instruction of the configuration a use of the limit. – SC registers IMPLIED_STRT for the configuration as 1. – Transition IMPLIED_STRT will be derived as the difference between IMPLIED_STRT of 'To Configuration' and IMPLIED_STRT of 'From Configuration'. The derived transition implied start will not be equal to the transition implied starts appropriate for this type of limitation. Transition IMPLIED_STRT must be set to 1 for every

Scenario	Use Plan Limitation Type
	transition into the configuration. – Functionality does not support ability to model opportunity cost for this type of plant level limitation. The SC needs to identify the derived transitions are not compatible with plan. The CAISO will negotiate an opportunity cost adder.

The next table relates the anticipated scenarios for MSG use limitation types to the values to be submitted by the SC in the MSG_CONFIG tab for IMPLIED_STRT to the configuration and the values that will be set for the feasible transitions.

For each Scenario, the first three blue columns represent the possible movements of the MSG resource from offline to online into each configuration. These values are to be submitted in the MSG_Config tab of the GRDT at the CONFIG_ID level. For example, the value registered for Configuration 1 is the IMPLIED_STRT from offline to Configuration 1 (i.e. $S_{0,1}$). The same pattern follows for each configuration of the MSG resource.

The next three orange columns will be values set by the CAISO through the approval of the ULPDT and its valid implied starts. The CAISO will set the IMPLIED_STRTS used downstream in internal CAISO systems as shown based on the scenarios. The columns represent the number of starts that count towards the start limitation as the result of a transition from a 'From Configuration' to a 'To Configuration', for example a transition from Configuration 1 to Configuration 2 is denoted as $T_{1,2}$. The same pattern follows for all feasible transitions.

Supported Y/N	Scenario	Use Plan Limitation Type	$S_{0,1}$	$S_{0,2}$	$S_{0,3}$	$T_{1,2}$	$T_{1,3}$	$T_{2,3}$
Y	PLANT_A	Plant level limitation that does not consider a transition a "start" where each start=1	1	1	1	0	0	0
N Notify CAISO MSG needs negotiation	PLANT_B	Plant level limitation that does not consider a transition a "start" where each start=number of CT starts	1	2	3	0	0	0

Y	PLANT_C	Plant level limitation that does consider a transition a “start” where each start or transition=number of CT starts	1	2	3	1	2	1
Y	CONFIG_A	Configuration level limitation that does consider a transition a “start” where each start or transition=number of CT starts	1	2	3	1	2	1
N Notify CAISO MSG needs negotiation	CONFIG_B	Configuration level limitation that does consider a transition a “start” where each start or transition=1 (E.G. C3 Limitation)	0	0	1	0	1	1

The following table illustrates the scenarios of MSG use limitation plans that imply a combination of plant-level and configuration-level limitations. Of the anticipated combinations of the plant or configuration scenarios described above, only one of the combinations can be accurately registered and modelled. The combination of PLANT_C and CONFIG_A can be registered with a USE_LIMIT_TYPE of ‘START’ with its associated configuration implied starts. The other combinations should be registered as USE_LIMIT_TYPE equal to ‘OTHER’ so the CAISO can initiate further discussions on registering limitations or negotiating opportunity costs.

Plant and Configuration Combination – Modelled (‘START’) or Negotiated (‘OTHER’)

Plant & Configuration Combinations that can be modelled	**CONFIG_A**	**CONFIG_B**
PLANT_A	‘OTHER’	‘OTHER’
PLANT_B	‘OTHER’	‘OTHER’
PLANT_C	‘START	‘OTHER’

The following sections provide examples for most of the anticipated MSG use limitation scenarios. Examples 1-4 provides examples for scenarios in which the MSG resource has either

a plant level or configuration level limitation. Examples 5-8 provides examples for the scenarios in which the MSG has a combination of both plant and configuration level limitations.

The Scenarios PLANT_A and PLANT_C are the scenarios that the CAISO considers more likely to be registered, and examples provided for these below. Note – any use limitations with supporting documentation that implies limitations under scenario PLANT_B and CONFIG_B cannot be accurately registered. The SC will need to register the USE_LIMIT_TYPE of the limitation as 'OTHER' so it can be evaluated for a negotiated opportunity cost.

Example 1: Plant level limitation that does not consider a transition a "start" where each start=1 (PLANT_A)

The resource is limited to 300 starts per year where transitions are not considered a start that counts against the resource's annual start limitation. The SC of the resource will fill out the use-limited plan data template to reflect the annual start limitation as shown below. The SC would input an implied start of one per configuration to reflect that transitions are not considered a "start" against the limitation. The resulting implied starts for each transition will then be calculated by the CAISO as zero (Implied start "to-configuration" minus implied start "from-configuration").

ULPDT

SC_ID	RES_ID	CONFIG_ID	USE_LIMIT_TYPE	GRANULARITY	PLAN_STRT_DT_TM	PLAN_END_DT_TM	LIMITATION
SC_1	RES_A		START	ANNUALLY	1/1/2018	12/31/2018	300

Implied Starts in GRDT

CONFIG_1	CONFIG_2	CONFIG_3
1	1	1

The CAISO derives transition implied starts based on configuration implied starts data, which is shown below for each feasible transition.

Implied Starts by Transition

From Config	To Config	GRDT Tab	Mechanism	Implied Starts
Offline	CONFIG_1	MSG_CONFIG	SC registers	1
Offline	CONFIG_2	MSG_CONFIG	SC registers	1

Offline	CONFIG_3	MSG_CONFIG	SC registers	1
CONFIG_1	CONFIG_2	TRANSITION	CAISO derives	0
CONFIG_1	CONFIG_3	TRANSITION	CAISO derives	0
CONFIG_2	CONFIG_3	TRANSITION	CAISO derives	0
CONFIG_1	Offline	TRANSITION	CAISO derives	0
CONFIG_2	Offline	TRANSITION	CAISO derives	0
CONFIG_3	Offline	TRANSITION	CAISO derives	0

Example 2: Plant level limitation that does consider a transition a "start" where each start or transition=number of CT starts (PLANT_C)

The resource is limited to 300 starts per year where transitions are considered a start that counts against the resource's annual start limitation. The following implied starts indicate that if the resource is directly started into configuration 2, it uses up two of the fired turbine starts it is allowed during the year. Furthermore, if it then transitions into configuration 3, one additional fired turbine start is used. The resulting implied starts for each transition will then be calculated by the CAISO as one (Implied start "to-configuration" minus implied start "from-configuration").

ULPDT

SC_ID	RES_ID	CONFIG_ID	USE_LIMIT_TYPE	GRANULARITY	PLAN_STRT_DT_TM	PLAN_END_DT_TM	LIMITATION
SC_1	RES_A		START	ANNUALLY	1/1/2018	12/31/2018	300

Implied Starts in GRDT

CONFIG_1	CONFIG_2	CONFIG_3
1	2	3

The CAISO derives transition implied starts based on configuration implied starts data, which is shown below for each feasible transition.

Implied Starts by Transition

From Config	To Config	GRDT Tab	Mechanism	Implied Starts
Offline	CONFIG_1	MSG_CONFIG	SC registers	1
Offline	CONFIG_2	MSG_CONFIG	SC registers	2
Offline	CONFIG_3	MSG_CONFIG	SC registers	3
CONFIG_1	CONFIG_2	TRANSITION	CAISO derives	1
CONFIG_1	CONFIG_3	TRANSITION	CAISO derives	2
CONFIG_2	CONFIG_3	TRANSITION	CAISO derives	1
CONFIG_1	Offline	TRANSITION	CAISO derives	0
CONFIG_2	Offline	TRANSITION	CAISO derives	0
CONFIG_3	Offline	TRANSITION	CAISO derives	0

Example 3: Configuration level limitation that does consider a transition a "start" where each start or transition=number of CT starts (CONFIG_A)

Configuration 3 can only be started 50 times a year based on the number of turbine starts. The implied starts indicate that C3 can only start turbines 50 times per year. The configuration level limitation is based on number of turbine starts, which can be used through either starts or transitions. For example, if the resource was started from offline to C1 and then transitioned to C3 that should be considered as number of additional turbines needed to be started to transition to the higher C3 configuration.

ULPDT

SC_ID	RES_ID	CONFIG_ID	USE_LIMIT_TYPE	GRANULARITY	PLAN_STRT_DT_TM	PLAN_END_DT_TM	LIMITATION
SC_1	RES_A	CONFIG_3	START	ANNUALLY	1/1/2018	12/31/2018	50

Implied Starts in GRDT

CONFIG_1	CONFIG_2	CONFIG_3
1	2	3

The CAISO derives transition implied starts based on configuration implied starts data, which is shown below for each feasible transition.

Implied Starts by Transition

From Config	To Config	GRDT Tab	Mechanism	Implied Starts
Offline	CONFIG_1	MSG_CONFIG	SC registers	0
Offline	CONFIG_2	MSG_CONFIG	SC registers	0
Offline	CONFIG_3	MSG_CONFIG	SC registers	3
CONFIG_1	CONFIG_2	TRANSITION	CAISO derives	0
CONFIG_1	CONFIG_3	TRANSITION	CAISO derives	2
CONFIG_2	CONFIG_3	TRANSITION	CAISO derives	1
CONFIG_1	Offline	TRANSITION	CAISO derives	0
CONFIG_2	Offline	TRANSITION	CAISO derives	0
CONFIG_3	Offline	TRANSITION	CAISO derives	0

Example 4: Configuration level limitation that does consider a transition a "start" where each start or transition=1 (CONFIG_B)

Configuration 3 can only be started 50 times a year based on number of actual starts or transitions. The second limitation implied starts indicate that C3 can only be actually started or transitioned into 50 times per year. The configuration level limitation is based on actual starts or transitions and not the turbine starts. For example, if the resource were started from offline to C1 and then transitioned to C3 that should only be considered one start against the limit on C3.

ULPDT

SC_ID	RES_ID	CONFIG_ID	USE_LIMIT_TYPE	GRANULARITY	PLAN_STRT_DT_TM	PLAN_END_DT_TM	LIMITATION
SC_1	RES_A	CONFIG_3	START	ANNUALLY	1/1/2018	12/31/2018	50

Implied Starts in GRDT

CONFIG_1	CONFIG_2	CONFIG_3
1	1	1

The CAISO derives transition implied starts based on configuration implied starts data, which is shown below for each feasible transition.

Implied Starts by Transition

From Config	To Config	GRDT Tab	Mechanism	Implied Starts
Offline	CONFIG_1	MSG_CONFIG	SC registers	0
Offline	CONFIG_2	MSG_CONFIG	SC registers	0
Offline	CONFIG_3	MSG_CONFIG	SC registers	1
CONFIG_1	CONFIG_2	TRANSITION	CAISO derives	0
CONFIG_1	CONFIG_3	TRANSITION	CAISO derives	1
CONFIG_2	CONFIG_3	TRANSITION	CAISO derives	1
CONFIG_1	Offline	TRANSITION	CAISO derives	0
CONFIG_2	Offline	TRANSITION	CAISO derives	0
CONFIG_3	Offline	TRANSITION	CAISO derives	0

Because the transition IMPLIED_STRTS need to be set at different values than the functionality will calculate based on the difference of the 'To Configuration' and 'From Configuration' implied starts, CONFIG_B cannot be registered accurately. SC will need to register the USE_LIMIT_TYPE of the limitation as 'OTHER' so it can be evaluated for a negotiated opportunity cost.

If a MSG resource has start limitations on both plant and configuration levels that require different implied start counts for each configuration based on the plant and configuration(s) limitation(s), the CAISO cannot support multiple IMPLIED_STRTS value per MSG resource or configuration so cannot model these types of combined plant and configuration(s) limitations. The SC should register the MSG resource or MSG configuration(s) limitations as the USE_LIMIT_TYPE='OTHER' and the IMPLIED_STRTS should be NULL.

If an MSG resource has plant level and configuration level start limits that are the same for each configuration based on the plant and configuration(s) limitations, the SC should register the IMPLIED_STRTS values by configuration and the same value will be used to count number of starts that count towards the plant or the configuration(s) limitations.

Example 5: PLANT_A and CONFIG_B Combination

Example 5 is an example of plant and configuration level limitations that cannot be modelled either as a combination or separately since CONFIG_B's transition implied starts would not be derived correctly. The combination of limitations on this MSG resource are:

The resource is limited to 300 CAISO start-up instructions per year limitation where transitions do not count against the resource's annual start limitation.

Configuration 3 can be started or transitioned 50 times a year based on number of CAISO start-up instruction or transition instructions.

ULPDT

SC_ID	RES_ID	CONFIG_ID	USE_LIMIT_TYPE	GRANULARITY	PLAN_STRT_DT_TM	PLAN_END_DT_TM	LIMITATION
SC_1	RES_A		START	ANNUALLY	1/1/2018	12/31/2018	300
SC_1	RES_A	CONFIG_3	START	ANNUALLY	1/1/2018	12/31/2018	50

SC would register the IMPLIED_STRTS for each configuration as follows.

Implied Starts in GRDT

CONFIG_1	CONFIG_2	CONFIG_3
1	1	1

The CAISO derives transition implied starts based on configuration implied starts data, which is shown below for each feasible transition. The CAISO would determine the transitions shown in orange for the PLANT_A limitation. The transition implied starts shown for CONFIG_B are the implied starts based on the plan documentation, which current functionality cannot correctly derive.

Implied Starts by Transition

From Config	To Config	Mechanism	Implied Starts – PLANT_A	Implied Starts – CONFIG_B
Offline	CONFIG_1	SC registers	1	0
Offline	CONFIG_2	SC registers	1	0
Offline	CONFIG_3	SC registers	1	1

CONFIG_1	CONFIG_2	CAISO derives	0	0
CONFIG_1	CONFIG_3	CAISO derives	0	1
CONFIG_2	CONFIG_3	CAISO derives	0	1
CONFIG_1	Offline	CAISO derives	0	0
CONFIG_2	Offline	CAISO derives	0	0
CONFIG_3	Offline	CAISO derives	0	0

Because the IMPLIED_STRTS for a given configuration need to be different to represent accurately the limitations, this combination cannot be registered accurately. SC will need to register the USE_LIMIT_TYPE of the limitation as 'OTHER' so it can be evaluated for a negotiated opportunity cost.

Example 6: PLANT_A and CONFIG_A Combination

Example 6 is an example of plant and configuration level limitations that cannot be modelled as a combination since the configuration implied starts are not the same for the plant and configuration level limitations. The combination of limitations on this MSG resource are:

> The resource is limited to 300 CAISO start-up instructions per year limitation where transitions do not count against the resource's annual start limitation.
>
> Configuration 3 can be started or transitioned 50 times a year based on the number of turbine starts.

SC would register the IMPLIED_STRTS for each configuration as follows and the CAISO would derive the transition implied starts shown in orange.

Implied Starts by Transition

From Config	To Config	Mechanism	Implied Starts – PLANT_A	Implied Starts – CONFIG_A
Offline	CONFIG_1	SC registers	1	1
Offline	CONFIG_2	SC registers	1	2
Offline	CONFIG_3	SC registers	1	3
CONFIG_1	CONFIG_2	CAISO derives	0	1
CONFIG_1	CONFIG_3	CAISO derives	0	2

CONFIG_2	CONFIG_3	CAISO derives	0	1
CONFIG_1	Offline	CAISO derives	0	0
CONFIG_2	Offline	CAISO derives	0	0
CONFIG_3	Offline	CAISO derives	0	0

Because the IMPLIED_STRTS for a given configuration need to be different to represent accurately the limitations, this combination cannot be registered accurately. SC will need to register the USE_LIMIT_TYPE of the limitation as 'OTHER' so it can be evaluated for a negotiated opportunity cost.

Example 7: PLANT_C and CONFIG_B Combination

Example 7 is an example of plant and configuration level limitations that cannot be modelled as a combination since the configuration implied starts are not the same for the plant and configuration level limitations. The combination of limitations on this MSG resource are:

> The resource is limited to 300 turbine starts per year limitation where transitions count against the resource's annual start limitation.
>
> Configuration 3 can be started or transition 50 times a year based on number of CAISO start-up instructions or transition instructions.

SC would register the IMPLIED_STRTS for each configuration as follows and the CAISO would determine the transitions shown in orange.

Implied Starts by Transition

From Config	To Config	Mechanism	Implied Starts – PLANT_C	Implied Starts – CONFIG_B
Offline	CONFIG_1	SC registers	1	0
Offline	CONFIG_2	SC registers	2	0
Offline	CONFIG_3	SC registers	3	1
CONFIG_1	CONFIG_2	CAISO derives	1	0
CONFIG_1	CONFIG_3	CAISO derives	2	1
CONFIG_2	CONFIG_3	CAISO derives	1	1
CONFIG_1	Offline	CAISO derives	0	0

CONFIG_2	Offline	CAISO derives	0	0
CONFIG_3	Offline	CAISO derives	0	0

Because the IMPLIED_STRTS for a given configuration need to be different to represent accurately the limitations, this combination cannot be registered accurately. SC will need to register the USE_LIMIT_TYPE of the limitation as 'OTHER' so it can be evaluated for a negotiated opportunity cost.

Example 8: PLANT_C and CONFIG_A Combination

Example 8 is an example of plant and configuration level limitations that can be modelled as a combination since the configuration implied starts are the same and the derived transition implied starts are representative of the use limitation plan for both the plant and configuration level limitations. The combination of limitations on this MSG resource are:

> The resource is limited to 300 turbine starts per year limitation where transitions count against the resource's annual start limitation.
>
> Configuration 3 can be started or transitioned 50 times a year based on the number of turbine starts.

SC would register the IMPLIED_STRTS for each configuration as follows and the CAISO would determine the transitions shown in orange.

Implied Starts by Transition

From Config	To Config	Mechanism	Implied Starts – PLANT_C	Implied Starts – CONFIG_A
Offline	CONFIG_1	SC registers	1	1
Offline	CONFIG_2	SC registers	2	2
Offline	CONFIG_3	SC registers	3	3
CONFIG_1	CONFIG_2	CAISO derives	1	1
CONFIG_1	CONFIG_3	CAISO derives	2	2
CONFIG_2	CONFIG_3	CAISO derives	1	1
CONFIG_1	Offline	CAISO derives	0	0
CONFIG_2	Offline	CAISO derives	0	0
CONFIG_3	Offline	CAISO derives	0	0

Because the IMPLIED_STRTS counts for both PLANT_C and CONFIG_A are the same value for each configuration and transitions, the SC should register both limitations in the ULPDT under the USE_LIMIT_TYPE='START'. PLANT_C limitation would be registered under the MSG resource ID with no configuration ID and CONFIG_A limitation would be registered in ULPDT under the configuration ID for configuration 3. In the GRDT MSG_CONFIG tab the IMPLIED_STRTS would be registered as CONFIG_1=1, CONFIG_2=2, and CONFIG_3=3. The transitions will be derived by the CAISO as the difference (Implied start "To Configuration" minus implied start "From Configuration").

2.1.15.6 Multi-Stage Generator with Registered Run Hour Limitation

MSG Resources may register run hour limitations on the MSG plant level or at the MSG configuration level. Both plant-level and configuration-level run hour limitations will be considered in the opportunity cost calculator. The CAISO's Day-Ahead and Real-Time Markets will enforce the run hour limitation through the bid-in Daily Energy Limit only at the MSG plant level and cannot enforce the configuration-level Daily Energy Limits.

2.1.16 Conditionally Available Resource

A Scheduling Coordinator may apply to register a resource with the CAISO as a Conditionally Available Resource (CAR) if the resource has one or more operational or regulatory limits that do not qualify it as a Use-Limited Resource, but still impose frequent and recurring periods of unavailability. The same resource may have one or more limits that qualify it as a Use-Limited Resource and one or more limits that would qualify it as a CAR. If a resource qualifies as both a Use-Limited Resource and a CAR, the Scheduling Coordinator representing the resource may register the resource under both statuses at the same time.

Examples of why a resource might fall in this category are the following:

- Regulatory limitation due to noise abatement
- Hybrid technology, such as a wind or solar resource with a battery component

The CAR designation exempts a resource from bid generation if it provides RA capacity. A CAR resource also qualifies for a unique must offer obligation under section 40.6.4.1 and for more details this must offer obligation please reference sections 7.1.2 and 7.1.3 of the Reliability Requirements BPM. There are several categories of resources that are exempt from bid

generation pursuant to Tariff section 40.6.8(e). If a resource falls into one of those other categories, then there is no need to register as a CAR to be exempt from bid generation.

CARs that are not registered as a Use Limited resource are not eligible to use any of the "use limit reached" outage types and are not eligible for opportunity cost adders. (If CAR has eligible "use-limits" that it can qualify separately as a Use-Limited Resource and terminate its status as a CAR.)

To apply to register a resource as a CAR, the scheduling coordinator must submit a CIDI case with supporting documentation including, but not limited to, the following:

- A detailed explanation of why the resources faces frequent and recurring periods of unavailability because of an operational or regulatory limitation that would make bid generation infeasible or impractical..
- Documentation, such as environmental permits or operating manuals, as well as page numbers or section numbers in the supporting documentation, substantiating the detailed explanation.
- Any additional data to help the CAISO to understand the operating characteristics of the unit, such as the absence of specific tariff rules that apply. One example is hybrid resources of wind and solar with onsite storage and operating under a single Resource ID. These hybrid resources are not eligible to be a VER, but should be exempt from bid insertion for the same reasons VERS are.

Upon submission of the CIDI case, the CAISO will review the submitted material and either: (1) approve the request; (2) deny the request; or (3) request additional information for further review. If the CAISO approves the request, it will set the MOO_QUALIFIED flag to N in Master File, which will exempt the resource from generated bid insertion. CAISO will track the CAR resources manually until a separate flag is added to the Master File in a future project. The Scheduling Coordinator may refer to the existing MOO_QUALIFIED flag in the Resource Data Template (RDT) to confirm that a resource has been flagged as exempt from bid insertion.

2.1.17 Non-Dispatchable Resource

A Scheduling Coordinator may apply to register a resource with the CAISO as a Non-Dispatchable Resource if, in the Real-Time Dispatch, it is incapable of following CAISO direction

either to: (a) increase its output or consumption or energy; or (b) curtail its output or consumption or energy. A resource can qualify as a Non-Dispatchable Resource if it meets either condition (a) or condition (b); it need not meet both to qualify. The tariff definition of a Non-Dispatchable Resource identifies certain Qualifying Facilities as examples of resources that meet the general definition. The Non-Dispatchable Resource designation exempts a resource from bid generation if it has capacity that receives RA credit. Such resources are not, however, exempt from RAAIM unless they separately qualify for a RAAIM exemption.

To apply to register a resource as a Non-Dispatchable Resource, the scheduling coordinator must submit a CIDI case with supporting documentation including, but not limited to, the following:

- A detailed explanation of why the resources cannot be increased or curtailed at the direction of the CAISO in the Real-Time Dispatch to Supply or consume Energy.
- Documentation, such as contracts, as well as page numbers or section numbers in the supporting documentation, substantiating the detailed explanation.
- Any additional data to help the CAISO to understand the resource's inability to respond to CAISO directions in the Real-Time Dispatch.

Upon submission of the CIDI case, the CAISO will review the submitted material and either: (1) approve the request; (2) deny the request; or (3) request additional information for further review. If the CAISO approves the request, it will set the MOO_QUALIFIED flag to N in Master File, which will exempt the resource from generated bid insertion. The scheduling coordinator may refer to the existing MOO_QUALIFIED flag in the Resource Data Template (RDT) to confirm that a resource has been flagged as exempt from bid insertion.

Master File has a "Dispatchable" flag but the CAISO currently uses it for purposes other than implementing the bid generation exemption for Non-Dispatchable Resources. At this time scheduling coordinators should not rely on a resource's value for "Dispatchable" in the RDT to confirm whether or not the CAISO has accepted a registration as a "Non-Dispatchable Resource." At some point in the future the CAISO will repurpose the "Dispatchable" flag in Master File to reflect those resources that the CAISO has recognized as meeting the tariff definition of a "Non-Dispatchable Resource."

2.1.18 Run-of-River Hydro (ROR)

This is a type of hydroelectric generation plant that has no water storage beyond what is necessary to maintain sufficient head pressure. Such resources can be subject to seasonal river flows and have variable output across time. A ROR, per section 40.9.2(b), is exempt from RAAIM for any local or system RA capacity it provides. A ROR also qualifies for a unique must offer obligation under section 40.6.4.1 and for more details this must offer obligation please reference sections 7.1.2 and 7.1.3 of the Reliability Requirements BPM. All hydro resources are exempt from bid generation, so RORs also enjoy that exemption.

A Scheduling Coordinator must register its resource with the CAISO as a ROR for the resource to receive any special accommodations allowed to RORs under the tariff. To apply to register a resource as a ROR, the scheduling coordinator must submit a CIDI case with supporting documentation including, but not limited to, the following:

- An affirmative statement from the Scheduling Coordinator that the resource has no water storage beyond whatever storage is necessary to maintain sufficient head pressure to operate consistent with good utility practice.

- Documentation substantiating the statement. This can include environmental permits, operating manuals, site licenses, or aerial/satellite photography. The Scheduling Coordinator should include citations to the page numbers or section numbers in the supporting documentation.

- Any additional data to help the CAISO to understand the requested registration.

Upon submission of the CIDI case, the CAISO will review the submitted material and either: (1) approve the request; (2) deny the request; or (3) request additional information for further review. The CAISO will not implement a Master File flag for RORs until October 1, 2020. This Master File flag is key to processing the RAAIM exemption. Settlement statements generated before that calendar date will not reflect the RAAIM exemption. Once the Master File flag is implemented, the CAISO will apply the RAAIM exemption to recalculation settlement statements for trade dates prior to October 1, 2020. For accepted ROR requests, the CAISO will apply the RAAIM exemption as of the trade date corresponding to when the CIDI ticket requesting ROR status was first submitted to the CAISO.

2.1.19 Co-Located Resources

Co-located Resource: A Generating Unit with a unique Resource ID that is part of a Generating Facility with other Generating Units. An WEIM Participating Resource with a unique Resource ID that is part of a single resource with other WEIM Participating Resources.

Co-located resources may be a combination of different generation technologies or the same generation technology that are part of a single Generating Facility behind a single point of interconnection each of which participates in the CAISO markets as distinct resources with their own resource ID. The collection of resources behind the point of interconnection (POI) are optimized by the CAISO's market using the entire collection of bids or self-schedules. Each resource is individually metered and telemetered. Generally, the combined Pmax and Pmin (in the case of energy storage) of co-located resources may not exceed the Generating Facility's Interconnection Service Capacity. If, however, an Interconnection Customer for a Generating Facility with co-located resources elects to utilize the CAISO's Aggregate Capability Constraint, the co-located resources' combined Pmax and Pmin may exceed the Generating Facility's Interconnection Service Capacity. Additionally, an WEIM Participating Resource Scheduling Coordinator may elect to utilize the CAISO's Aggregate Capability Constraint so that the Pmaxs and Pmins of WEIM Participating Resources and WEIM Non-Participating Resources that are part of a single resource behind a point of interconnection may exceed that resource's interconnection service capacity. Per section 27.13 of the CAISO Tariff, the following resources are not eligible to use the ACC: Multi-Stage Generators, Proxy Demand Response, Pump Storage Hydro Units, Metered Subsystems, and Use-Limited resources.

2.1.19.1 Business process for Co-Located Resources to elect to utilize Aggregate Capability Constraint

The CAISO will process requests for Co-located Resources to utilize the Aggregate Capability Constraint in the following manner:

CAISO BAA

Requests to utilize the Aggregated Capability Constraint for Co-located Resources located within the CAISO BA must be submitted to regulatorycontracts@caiso.com.

- Interconnection Customer or the Pseudo-Tie Generating Facility will elect to have Co-located Resource modeled utilizing Aggregate Capability Constraint (ACC) located at its

Point-of-Interconnection (POI) to the CAISO Controlled Grid or at its Intertie point to the CAISO BAA respectively through a revision to Schedule 1 of the Participating Generator Agreement (PGA) and/or Participating Load Agreement (PLA), Pseudo-Tie Participating Generator Agreement (PPGA) and direct scheduling coordinator(s) for the resources to submit market model data to Master File.

- The CAISO will map all co-located resources at a single Generating Facility to a specific Aggregate Capability Constraint (ACC). This constraint will reflect the interconnection service capacity at the Generating Facility's point of if interconnection for purposes of the combined PMax and PMin of the Co-located Resources. The CAISO market will observe this constraint in issuing any awards and dispatches to the co-located resources at the Generating Facility. Co-Located Resources at a single Generating Facility will have their energy dispatch optimized by their economic bids while their aggregate awards and energy dispatch will be bound by the minimum and maximum Aggregate Capability Constraint (ACC) limits applied to those associated resources.
- Operators can override the MW amount of reduction adjustment for the ACC max limit, incremental adjustment for the ACC min limit.
- Operators can set the ACC override start and end time (aligning with market intervals), the system will revert to the Master File ACC limits once the market horizon passes beyond the override's end time.

EIM BAA

Requests to utilize the Aggregated Capability Constraint for new Co- located Resources located in WEIM BAAs, must be included in the resource SC selection letter and submitted to screquests@caiso.com. For existing WEIM Co-located Resources, Aggregated Capability Constraint requests will be submitted as a CIDI request.

- Election of co-located status by the WEIM resource owner (whether resource is participating or non-participating) will be managed through a Scheduling Coordinator Selection Letter(s).
- Additionally, ACC information details and resource-to-ACC mapping will also need to be included in the SC Selection Letter, which is submitted by the WEIM Entity and approved by the WEIM SC. The following information will be required from WEIM BAA Entity through the SC Selection Letter:
    - ACC Identifier that will have two or more resources.
    - ACC Point-of-Interconnection (POI) Location (substation, voltage level)
    - Each ACC's Max, Min Limit (positive = injection, negative = withdrawal)

- Mapping of ACC's associated Co-Located Resource IDs for Participating and Non-Participating resources by SC.
- Effective start date of ACC activation

- Within each individual WEIM BAA, Operators will be able to reduce ACC max and min limit for a temporary time period (in response to operating conditions) where the reduction value may only be a non-negative value below the max and min limit defined in Master File; max limit shall revert to its Master File default once reduction is released.
- Within each individual WEIM BAA, Operators can set the ACC override start and end time (aligning with market intervals), the system will revert to the Master File ACC limits once the market horizon passes beyond the override's end time

2.1.19.2 Market Processes for Co-Located Resources

The CAISO will optimize and dispatch Co-Located Resources that are part of an Aggregate Capability Constraint in the day-ahead and real-time markets while enforcing this security constraint of the associated ACC.

The CASIO will enforce the Aggregate Capability Constraint in the market formulation by prohibiting the combined dispatch instructions of associated co-located resources from exceeding their maximum and minimum interconnection limits (in the positive injection and negative withdrawal directions, respectively). The CAISO will not apply a shadow price to the locational marginal price (LMP) of the Co-located Resource at its point-of-interconnection Pnode.

During time periods when the ACC is binding (either by its Max or Min limit), the CAISO will reduce Co-located Resources' self-schedules on the basis of scheduled MW amount only for those schedules in the direction of the binding constraint (e.g. LESR resources with charging self-schedules will not be curtailed if the ACC is binding in the direction of the POI injection into the grid).

During time periods when a co-located resources are producing energy (i.e. positive energy supply) while one or more associated Co-located Resource(s) are charging (i.e. negative energy supply), the CAISO market systems shall net the energy production and load from Co-located Resources utilizing the Aggregate Capability Constraint when enforcing the Aggregate Capability Constraint..

For example, Wind Resource #1 is producing 30 MW, Solar Resource #2 is producing 25 MW, and Battery Resource #3 is charging 10 MW at the same time under the same ACC ("ACC #1") with a Max Limit of 50 MW. Rather than curtail the resources to 50 MW, the CAISO's market

systems will evaluate all resources with a net injection to grid of 45 MW and not consider the ACC binding as long as the battery has the ability to charge in the market run's binding and advisory intervals.

2.1.19.3 Business process for Co-Located Resources to elect Off Grid Charging Indicator (OGCI)

The CAISO has created an Off Grid Charging Indicator (OGCI), allowing market participants to set a charging constraint on a co-located storage resource. The Indicator is located within the SIBR application on the hourly tab, allowing the resource's scheduling coordinator to enforce the OGCI. The CAISO will process requests for the Off Grid Charging Indicator in the following manner:

- The market participant will submit an OGCI request sheet to Regulatory Contracts to revise Schedule 1 of the Participating Generator Agreement (PGA).
- Regulatory Contracts will evaluate the resource's current market setup. The OGCI requires an Aggregated Capability Constraint (ACC) and can be initiated concurrently. Review of the intended use and function of the storage component within the Generator Interconnection Agreement will indicate if the storage resource can charge from the ISO controlled grid.
    - If the project was not studied to charge from the ISO controlled grid, and the GIA reflects a 0 MW grid charging capability, then the resource may not apply for an OGCI flag.
    - There may be only one master energy storage resource for each subordinate aggregated capability constraint.
    - All BESS resources falling under a subordinate aggregated capability constraint with an assigned master energy storage resource will share the same charging constraints.
    - To assign multiple master energy storage resources, the Master ACC must be assigned Subordinate Aggregated Capability Constraints with one master energy storage resource per Sub Aggregated Capability Constraint. See BPM section 2.1.22 for Sub Aggregated Capability Constraint information.

- Master File will set the flag for the Off Grid Controlling resource, once the PGA Schedule 1 is updated.
- The Off Grid Charging Indicator does not impact existing policy or requirements on the feasibility of bids or must-offer obligations for RA capacity. All applicable requirements and obligations within the Reliability Requirements BPM, Section 37, and Section 40 of the ISO Tariff, must continue to be met.

- The Off Grid Charge Indicator does not impact existing outage reporting obligations. All applicable requirements and obligations within the Outage Management BPM and Tariff section 9 must continue to be met.
- The Off Grid Charge Indicator functionality does not accommodate resources that are providing regulation. When the OGCI flag is selected for the hour, no regulation (up or down) will be awarded. Should a day-ahead award for regulation exist, OGCI selection will be ignored and the day ahead regulation will be protected.
- The State of Charge (SOC) is a binding parameter in the optimization, even when the OGCI is enabled. Therefore, the market will still take the SOC into account to ensure feasible awards.

2.1.20 High Sustainable Limit (HSL)

High Sustainable Limit (HSL): The instantaneous generating capability of a variable or intermittent Generating Unit or component thereof, updated through telemetry at the Generating Unit. HSL can exceed the PMax, ACC and/or POI of the resource and should reflect the true generation capability of the resource without any limitations. The HSL is a real-time estimate of the maximum output capability of a Co-located EIR or VER resource or the variable component of a Hybrid Resource based solely on the resource's physical properties (i.e. number of solar panels or wind turbines, and available inverters) and the fuel available to the resource based on current weather conditions. The CAISO also requires all EIRs or Hybrid Resources certified to offer ancillary services to provide the HSL. The HSL will be sent to the CAISO as a calculated, telemetered value and represents the approximate energy output capability of the resource at that moment in time. It is a calculated estimate; not a forecast. For instance, a resource's HSL sent as a telemetry to the CAISO at 10:00 PPT represents that resource's High Sustainable Limit at 10:00 PPT; it is not a forecast of the resource's capability at a future point in time.

Hybrid resources and co-located eligible intermittent resources are required to provide the CAISO with their HSL as a telemetry point. HSL can be set to update as frequently as the CAISO EMS polling rate of the RIG (every 1 or 4 seconds); however, Appendix Q of the CAISO Tariff specifies that the HSL shall update at a minimum every 12 seconds.

2.1.21 Hybrid Resources

Hybrid resource is defined as a Generating Unit, with a unique Resource ID at a single Point of Interconnection, with components that use different fuel sources or technologies. This hybrid resource definition will not apply to multi-stage generators or other resource configurations that have multiple units of a single fuel-type or single generation technology.

Additionally, hybrid resources must meet the minimum sizing requirements for both of the underlying generation components: 500 kW for any participating generator hybrid resource component and 100 kW for any storage hybrid resource components[8].

2.1.21.1 Market Processes for Hybrid Resources

Hybrid resources will be optimized and dispatched by the CAISO in the day-ahead and real-time markets like other resource types. Hybrids will receive market awards based on cleared schedules and bids submitted in the real-time market 75-minutes prior to the operating hour. The CAISO will expect hybrid resources to follow all CAISO market awards and dispatch instructions. The CAISO will assess uninstructed imbalance energy (UIE) at the real-time market prices for any deviation from dispatch instructions.

To mitigate for the timing granularity risk between bid submission and dispatch and help ensure that hybrid resources can meet dispatch awards for any real-time interval, the CAISO created hybrid dynamic limit functionality. This functionality will limit the dispatch instruction from the CAISO for portions of the bid curve that are unavailable for dispatch based on the dynamic limits submitted. Hybrid dynamic limits can be submitted up to 10 minutes before the associated RTD market interval (*i.e.*, up to T-10 minutes). This functionality replaces the burden on scheduling coordinators who would otherwise be required to submit outage cards to manage availability on a 5-minute basis. This functionality shall not be used to manage unit outages, Scheduling Coordinators are still required to submit outages via OMS for equipment-related outages.

For each 5-minute interval, CAISO requires Scheduling Coordinators to submit hybrid dynamic limits for hybrid resources. In other words, for every interval in which the hybrid resource has an economic bid, self-schedule, or a base schedule, the SC must submit a dynamic limit reflecting the hybrid resource's current operational capabilities to comply with Section 30.5.6.2 of the CAISO tariff. Scheduling Coordinators must use the SIBR UI or API, and may not rely on the automated functionality built into SIBR. Hybrid dynamic limits will include upper and lower economic limits for a rolling 6-hour window. If a Scheduling Coordinator fails to comply with the CAISO tariff and does not submit a hybrid dynamic limit, SIBR will insert limits equal to the upper and lower economic limits. If a Scheduling Coordinator did not or cannot submit hybrid dynamic limits, they are required to notify the CAISO as soon as possible to avoid unit deviation and possible system reliability issues.

[8] CAISO Tariff Section 4.6.3.2 requires participating generators to be 500 kW or greater. Pursuant to Order No. 841, the CAISO has proposed to lower the minimum capacity requirement for storage resources to 100 kW, effective December 3, 2019.

Scheduling coordinators may submit hybrid dynamic limits to reflect four scenarios: 1) ambient unavailability, 2) unavailability of renewable generation due to lack of fuel resource (*e.g.* wind, sun) 3) unavailability due to state of charge or 4) to reflect onsite charging. Scheduling coordinators that submit dynamic limits will no longer have to enter this unavailability into the outage management system. For hybrid variable energy components for which the CAISO is providing the forecast, the forecast for the component will not include outage information that is provided through OMS. This is due to the outage being input at the resource ID level versus the forecast which is provided at the component ID level. It will be up to the resource to include any outages for the variable energy components within their final value for the resource ID submitted to the dynamic limit tool. When consuming the hybrid dynamic upper/lower limits, the CAISO will use them in place of the upper/lower economic limits submitted in the clean bid. The CAISO will use the most restrictive Lower/Upper Economic Limits average value and rerated/derated PMax or Pmin. If the lower limit is higher than the self-schedule, the lower limit will be used. Hybrid dynamic limits may not be used to avoid curtailment of the VER component of a hybrid resource.

Because hybrid resources that recently commenced commercial operation (or converted from another resource type) likely have not begun receiving a VER forecast or configured their bidding systems to submit dynamic limits on an automated basis, they have insufficient data to submit dynamic limits. Accordingly, they do not need to use the SIBR UI or API to submit hybrid dynamic limits for 90 days from the date they began participating as a hybrid resource. During this period, scheduling coordinators may rely on the automated functionality built into SIBR during this 90 day period. After that 90 day period, the scheduling coordinator must use the SIBR UI or API to submit hybrid dynamic limits.

Withdrawal Limit

Scheduling Coordinators may limit their charging, i.e., their withdrawal limit, based upon an hourly biddable attribute available for either stand-alone or sub-ACCs. Setting the withdrawal limit to “Do not Charge from the Grid” effectively sets the withdrawal limit to zero. This setting will override any defined Master File non-zero limits. During hours where the stand-alone or sub-ACC constraint withdrawal limit equals zero, any battery (LES Unit Type) resources subject to the ACC constraint will not receive Regulation Up or Regulation Down awards in either the Day-Ahead or Real-Time markets. Additionally, for battery resources designated REM in the Master File, or receives a Real-Time Exceptional Dispatch (ED) or Manual Dispatch (MD) for WEIM entities, the stand-alone or sub-ACC constraint will also not be enforced when the withdrawal limit equals zero. If in the event operator-invention is required, an Operator-override is available on a case-by-case basis. Note that if there are Regulation awards from the Day

Ahead market, the withdrawal limit will be ignored and the prevailing Master File or Operator Limits enforced.

In the RTD, the CAISO will use reasonable efforts to use the 5-minute hybrid dynamic data submitted by the Scheduling Coordinator.

In the FMM, the CAISO will consider the upper and lower hybrid dynamic limit as the average of the 5-minute data corresponding to the 15-minute interval for hybrid resources in a similar fashion as for VER forecasts.

In the event some of the 5-minute hybrid dynamic limit data are missing, SIBR will automatically create the hybrid dynamic limits on the Scheduling Coordinator's behalf equal to the upper and lower economic limits. The hybrid dynamic limits created by SIBR will then be incorporated into the average of the 5-minute data corresponding to the 15-minute interval for hybrid resources in a similar fashion as for VER forecasts.

For each 5-minute interval, the CAISO will publish the resource's upper and lower economic limit to the real-time market for up to 60 intervals (5 hours total).

If the CAISO has used the hybrid dynamic upper/lower limits to replace the upper and/or lower economic limits submitted in the clean bid, the CAISO shall send the revised clean bid to downstream systems as a final bid in lieu of the clean bid.

For Real-Time Base Schedule, the CAISO will also use the average of the 5-minute hybrid dynamic limit data as calculated above for hybrid resources in the bid range capacity and flex ramp sufficiency tests. Note that the bid range capacity and flex ramp sufficiency tests occur before the deadlines to submit hybrid dynamic limits. For example, the binding bid range capacity test (RTBS-3) occurs at T-40, meaning that hybrid dynamic limits submitted after T-40 will not be considered in that test.

The CAISO will not optimize state of charge for hybrid resources. However, hybrid resources will be required to submit this information to the CAISO along with other telemetered values. This information may be used to verify that hybrid resources were capable of meeting dispatch instructions. Resource operators will need to manage the state of charge of any storage component through typical (Price, MW) bid submissions.

2.1.22 Master and Subordinate aggregate capability constraints (ACCs)

The primary purpose of the Aggregate Capability Constraint (ACC) is to ensure that multiple resources at a single point of interconnection (co-located resources) do not exceed point of

interconnection limits. A Master Aggregate Capability Constraint with no Subordinate Aggregate Capability Constraint is also referred to as a "standalone" Aggregate Capability Constraint and performs this function. Pseudo-tie resources may also be defined as part of an ACC constraint.

Subordinate Aggregate Capability Constraints can help off-takers reflect ownership or contractual rights for co-located resources. The Master Aggregate Capability Constraint is used alongside a Subordinate Aggregate Capability Constraint to ensure that in aggregate, all of the underlying co-located resources do not exceed interconnection limits.

- A Subordinate Aggregate Capability Constraints must be a pairing of two or more resources.
- Co-tenants that are signatory to a single GIA can set up Subordinate Aggregate Capability Constraints across the co-tenant's Participating Generator Agreements.
- Subordinate Aggregate Capability Constraints in aggregate must be equal to their associated Master Aggregate Capability Constraint.
- The Pmin of a Master Aggregate Capability Constraint may be zero MW only if the underlying Generating Facility was studied as not grid charging, and has a 0 MW grid charging capability in its applicable generator interconnection agreement.
    - At a resource level, only a hybrid resource with a BESS component can have a 0 MW Pmin. All BESS resources will have their Pmin verified via the Generator Resource Data Template.

The penalty parameters for the Master Aggregate Capability Constraints are set at a level higher than the power balance constraint such that the market optimization will not relax the master constraint. The penalty price for the Subordinate Aggregate Capability Constraint is set at a level below the master constraint and the power balance constraint. This will allow the market to relax the Subordinate Aggregate Capability Constraints occasionally during stressed system conditions when reliability is threatened. Subordinate Aggregate Capability Constraints should not be violated unless otherwise instructed by ADS. If the sum of DOTs for resources behind the same Subordinate Aggregate Capability Constraint is greater than the limit of that constraint, then the CAISO is indicating the constraint is relaxed and expects energy delivery at those DOTs.

For a Subordinate Aggregate Capability Constraint, if any of the resources in the constraint receive AS awards or qualified self-provision, ADS will set the FOLLOW_DOT flag as Y for VERs behind this Subordinate Aggregate Capability Constraint only. For the VERs outside this Subordinate Aggregate Capability Constraint but within the same Master Aggregate Capability Constraint, their FOLLOW_DOT shall not be impacted by this.

For a Standalone Aggregate Capability Constraint, if any of the resources within the constraint receive AS awards or qualified self-provision, ADS will set the FOLLOW_DOT flag as Y for VERs behind the Standalone Aggregate Capability Constraint.

The CAISO will validate that Master Aggregate Capability Constraint and Subordinate Aggregate Capability Constraint constraints include energy, AS, and FRU/FRD as follows:

$$\sum_{i \in S} (EN_i + RU_i + SR_i + NR_i + FRU_i) \leq UL$$

$$\sum_{i \in S} (EN_i - RD_i - FRD_i) \geq LL$$

Notation:

EN = Energy
RU = Regulation up
RD = Regulation Down
SR = Spinning Reserve
NR = Non spinning reserve
FRU = Flex ramp up
FRD = Flex ramp down
UL = Upper Limit
LL = Lower Limit

Example:

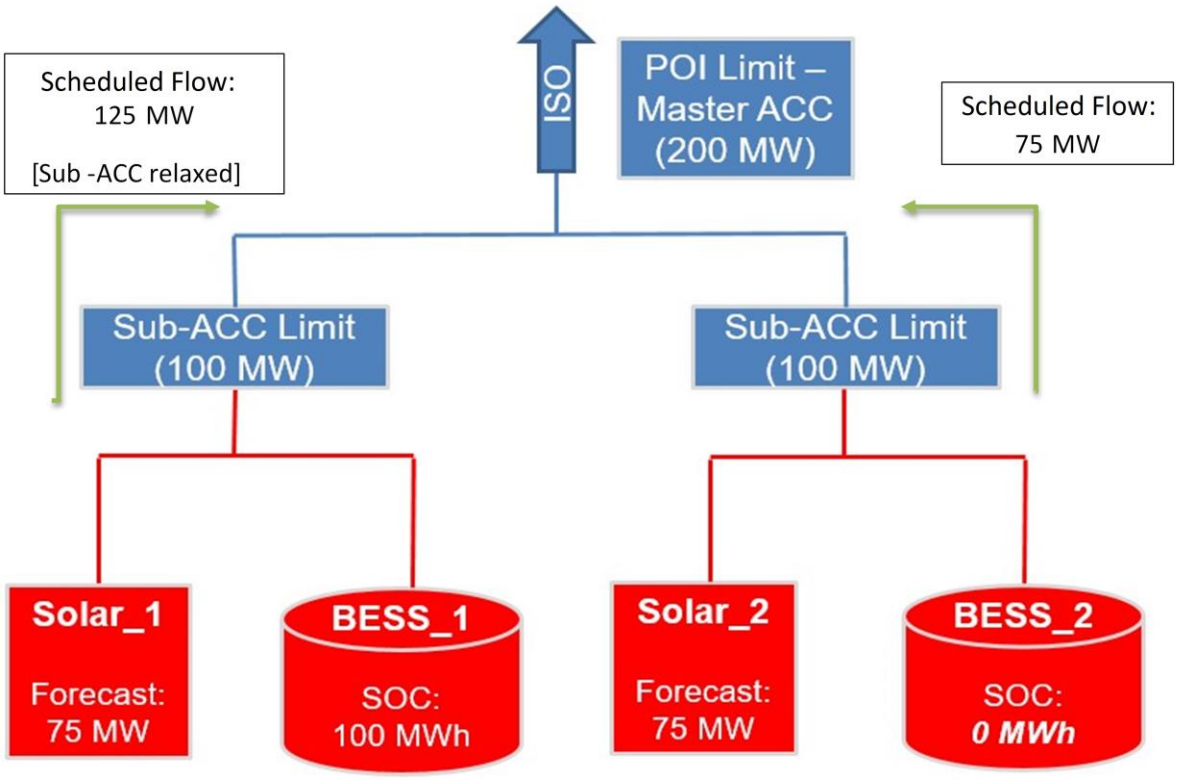
If a scheduling coordinator for one off-taker bids energy from a resource at a very high price and a scheduling coordinator for another off-taker bids energy at a very low price, the market software will not relax the subordinate aggregate capability constraint to access more energy from the co-located resources with a low energy bid. Doing so would create additional costs in the market optimization from the penalty price associated with relaxing the subordinate aggregate capability constraint. The market optimization will relax the subordinate constraint only when it is on the verge of a supply/demand imbalance and there is capacity at co-located resources behind one of subordinate aggregate capability constraints that is not available, with the implicit assumption that the corresponding Master Aggregate Capability Constraint is not at full capacity either. This unavailability could occur because of outages or other operating limitations such as state of charge availability from a storage resource. In this case, the market optimization may relax the subordinate constraint to reach supply from other co-located resources at the generating facility that is available to help balance demand, so long as the Master Aggregate Capability Constraint limit is not exceeded.

The following will illustrate this rule.

In this illustration, there are four co-located resources at a single generating facility, subject to two subordinate aggregate capability constraints and one master aggregate capability constraints. In this particular case, assume that each solar resource is modeled as a 100 MW resource and each storage resource is modeled as a +/- 50 MW resource. Both subordinate aggregate capability constraints reflect a contractual limit of 100 MW. The forecast for both solar resources is 75 MW; one storage resource has a state of charge of 100 MWh; the other storage resource is completely depleted of state of charge. The market is not able to dispatch the second storage resource above 0 MW because it has no state of charge.

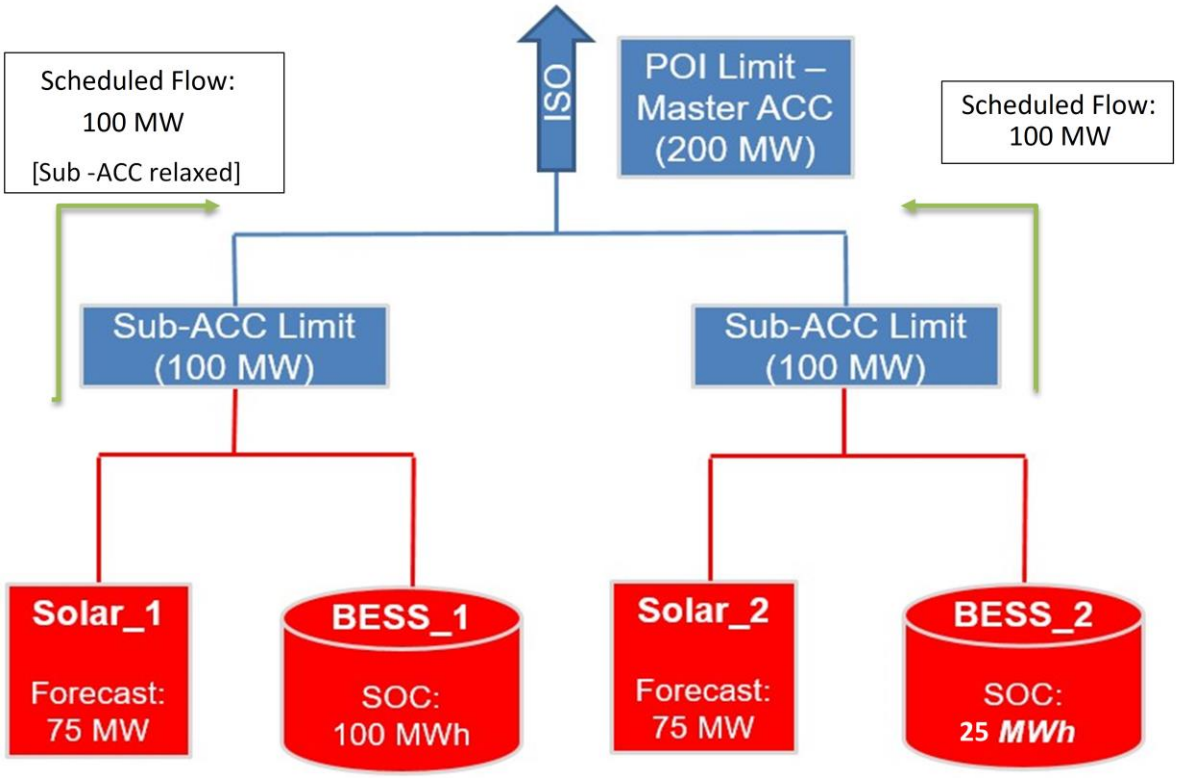
If grid conditions were tight such that the market is trying to utilize any available energy before relaxing the power balance constraint, the market will relax the first aggregate capability constraint by up to 25 MW and issue a dispatch instruction to the first storage resource at up to 50 MW. The ISO will still enforce the master aggregate capability constraint, which will prevent the market from dispatching the aggregate of all four co-located resources above 200 MW, even if more energy is available. This is illustrated in Figure 1.

Figure 1: The CAISO may relax the Subordinate Aggregate Capability Constraint



If, instead, the second storage resource had state of charge available and is able to receive positive dispatch instructions, up to at least 25 MW, the market software would not relax the first subordinate aggregate capability constraint. The proposed subordinate aggregate capability constraints ensure that the market optimization respects the contracted interconnection service capacity of 100MW dedicated to each off-taker when they are able to provide energy. The market optimization will only relax the subordinate aggregate capability constraints if it can source more power in order to avoid a power balance constraint violation and provided the optimization will not exceed the limit of the Master Aggregate Capability Constraint. This is illustrated in Figure 2.

Figure 2: Master Aggregate Capability Constraint is not violated



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

SCs can supply Energy into the CAISO markets from the following resources:

- Generating Units
- System Units – associated with Metered Subsystems
- Physical Scheduling Plants – group of tightly coupled Generating Units
- Participating Loads (modeled as a PSHU)
- System Resources – located outside the CAISO Balancing Authority Area

- Multi-Stage Generating Resources
- Submission of Virtual Supply Bids into the Day-Ahead Market at eligible locations[9]

SCs can purchase Energy from the CAISO markets, via:

- Loads within the CAISO Balancing Authority Area
- Exports from the CAISO Balancing Authority Area
- Submission of Virtual Demand Bids into the Day-Ahead Market at eligible locations.

2.2.2 Ancillary Services

The following types of Ancillary Services (AS) products are procured in the CAISO Markets. Section 4 of this BPM describes these Ancillary Services and their requirements in greater detail:

- Regulation Up (must be synchronized and able to receive AGC signals, and be able to deliver the AS Award within 10 minutes[10] based on the regulating ramp rate of the resource[11])
- Regulation Down (must be synchronized and able to receive AGC signals, and be able to deliver the AS Award within 10 minutes based on the regulating ramp rate of the resource)
- Spinning Reserve (must be synchronized, be able to deliver the AS Award within 10 minutes)
- Non-Spinning Reserve (must be able to deliver the AS Award within 10 minutes)

2.2.3 Residual Unit Commitment Capacity

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.

---

[9] Eligible locations for Virtual Bids submission are published on the CAISO web-site.

[10] In DAM, AS are procured for each Trading Hour. In RTM, AS from resources that are Dynamic System Resources are procured for each 15 minute interval. For resources that are identified as Non-Dynamic System Resources, AS capacity will be procured for the hour. In either case, when AS is dispatched, the associated Energy must be delivered within 10 minute according to the AS definition.

[11] Tariff Sections 8.4.1.1 and 30.5.2.6.1 provides that Ancillary Services Bid for Regulation must contain an upward and downward range of generating capacity over which the resource is willing to provide Regulation within a range from a minimum of 10 minutes to a maximum of 30 minutes. Initially the CAISO sets this requirement at 10 minutes.

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

Congestion Revenue Rights (CRRs) are financial instruments that may be used by their holders to offset the possible Congestion Charges that may arise in the IFM Day-Ahead Market for Energy. CRRs are settled based on the Marginal Cost of Congestion component of LMPs derived through IFM. Due to Virtual Bids having the ability to impact Congestion in the Day-Ahead Market, it is possible for an adjustment of CRR revenues to occur for CRR Holders that are also Convergence Bidding Entities (CBEs). This adjustment is called the CRR Settlement Rule and is explained in more detail in Attachment I in the BPM for Congestion Revenue Rights.

The *BPM for Congestion Revenue Rights* describes these rights in greater detail.

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.[12]

[12] 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.

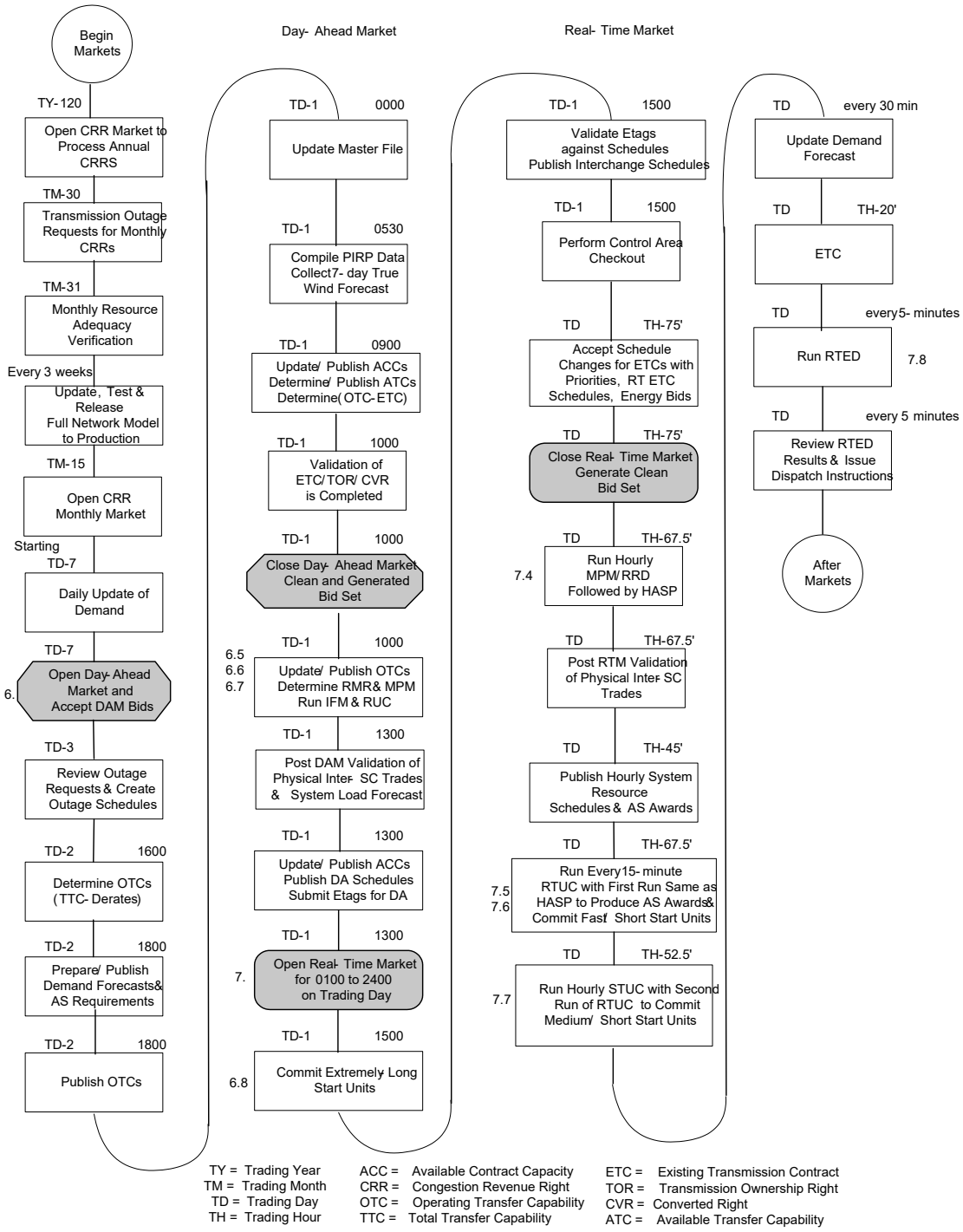


Exhibit 2-1: CAISO Markets – Overview Timeline

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 5.2~~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)

MPM is the first market process in the Day-Ahead Market. The MPM function consists of a test to determine which Bids to mitigate to address non-competitive constraints. If the test fails, the MPM mitigates the affected Bids for the relevant Trading Hours of the Trading Day. The MPM function is performed prior to the Integrated Forward Market process. Please refer to Section 6.5, Market Power Mitigation for a more detailed description of this process.

2.3.1.2 Integrated Forward Market

The IFM is a market for trading physical and virtual Energy, Ancillary Services. and Imbalance Reserves for each Trading Hour of the next Trading Day. IFM uses Clean Bids from SIBR[13] (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.

[13] 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 Reliability Capacity not scheduled in the IFM. Reliability Capacity Up (RCU) is procured to meet the difference between the CAISO Forecast of BAA Demand (CFBD) (including locational differences and adjustments) and the 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 CFBD.

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 BAA 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 CFBD. 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 BAA Demand in RUC. In addition, RUC may need to commit resources to the extent virtual supply has displaced 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 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

The commitment of resources that require a Start-Up Time of greater than 18 hours or notification earlier than the publication of the DAM is considered both in the RUC (explained in the previous section) and in the Extremely Long-Start Resource commitment process. Extremely Long- Start resources receive advisory startup-up instructions through the RUC process. Such start-up instructions are confirmed and made binding and communicated manually by CAISO operators. Refer to Section 6.8, Extremely Long-Start Resource commitment, for the details of this process.

2.3.2 Real-Time Processes

The primary goal of the RTM is to identify supplies to meet the CAISO Forecast of CAISO Demand and export schedules.

Bidding for the Real-Time Market (RTM) closes 75 minutes before the beginning of each Trading Hour (which in turn begins at the top of each hour). A sequence of processes determines the Market Clearing Prices for each Trading Hour. The prices resulting from these processes are used for the Real-Time Market Settlement.

Virtual Bids and Awards are not considered in the RTM.

The following subsections present an overview of these processes for the Trading Hour. Further details are presented in Section 7, Real-Time Processes.

2.3.2.1 Market Power Mitigation

The MPM functions for Real-Time are analogous to the same function that is performed for the DAM. For Real-Time, the MPM functions cover the Trading Hour and the resultant mitigated Bids are then used by the remaining Real-Time processes. Refer to Section 7.4, MPM for Real-Time.

The Day-Ahead Market and the Real-Time Market require separate Bid submissions. MPM re-evaluates all Bids in Real-Time.

Mitigation in the DAM is a separate process from Real-Time mitigation. As a result, a Bid could be mitigated in the DAM but not be mitigated in the RTM, and vice versa.

2.3.2.2 Hour-Ahead Scheduling Process

The Hour-Ahead Scheduling Process (HASP) is a process for scheduling Energy and AS based on the Bids submitted into the HASP from Scheduling Points. Refer to Section 7.5, Hour-Ahead Scheduling Process.

HASP is performed immediately after the Real-Time MPM. HASP produces HASP Advisory Schedules and advisory AS Awards for most resources except for resources with accepted Self-Schedule Hourly Blocks and awarded Economic Hourly Block Bids (but excluding an Economic Hourly Block Bid with Intra-Hour option), for which HASP Block Intertie Schedules are produced. All HASP Schedules for the Trading Hour are published approximately 45 minutes before the start of each Trading Hour.

HASP Block Intertie Schedules for the applicable HASP Trading Hour (i.e., between T and T+60 minutes) are determined on an hourly basis instead of on a 15-minute basis. This is

accomplished by enforcing constraints that ensure that the HASP Block Intertie Schedules for the 15-minute intervals are equal.

2.3.2.3 Real-Time Unit Commitment

Real-Time Unit Commitment (RTUC) is a market process for committing Short Start Units and awarding additional AS from Dynamic System Resources at 15-minute intervals. The RTUC function runs every 15 minutes and looks ahead in 15-minute intervals spanning the current Trading Hour and next Trading Hour. Refer to Section 7.6, Real-Time Unit Commitment. Also refer to Exhibit 6-2, Generating Unit Commitment Selection by Application, for a summary of the Unit Commitment processes.

The Fifteen Minute Market (FMM) is the second interval of the RTUC and its results produce the binding FMM

2.3.2.4 Short-Term Unit Commitment

Short-Term Unit Commitment (STUC) is a reliability function for committing Short Start Units to meet the CAISO Forecast of CAISO Demand. The STUC function is performed hourly and looks ahead three hours beyond the Trading Hour, at 15-minute intervals. Refer to Section 7.7, Short-Term Unit Commitment.

2.3.2.5 Real-Time Economic Dispatch

The Real-Time Economic Dispatch (RTED) is a market process that dispatches Imbalance Energy and dispatches Energy from AS and normally runs automatically every five minutes to produce Dispatch Instructions. The following two alternative modes to RTED are invoked under abnormal conditions:

- Real-Time Contingency Dispatch (RTCD)
- Real-Time Manual Dispatch (RTMD)

Refer to Section 7.8, Real-Time Economic Dispatch, for a description of the Dispatch algorithm.

2.3.2.5.1 Real-Time Contingency Dispatch

The Real-Time Contingency Dispatch (RTCD) function executes upon CAISO Operator action, usually following a Generating Unit or transmission system Contingency. The RTCD execution is for a single 10-minute interval and includes all Operating Reserves and all Real-Time Energy Bids in the optimization process. Refer to Section 7.9, Real-Time Contingency Dispatch.

2.3.2.5.2 Real-Time Manual Dispatch

The Real-Time Manual Dispatch (RTMD) function executes upon CAISO Operator action, usually when RTED and RTCD fail to provide a feasible solution. The RTMD is manually executed every five minutes for a single 5-minute interval. Refer to Section 7.10, Real-Time Manual Dispatch.

2.3.2.6 Market Orchestration

Market Participants can get important general market event information such as Real Time Market has opened, Day Ahead Market has closed, etc either through the CAISO portal or can these events can be sent as messages in the form of .xml files. CAISO has created a process for Market Participants interested in getting xml messages sent to them. Market Participants will need to download a registration form from the CAISO website. Market Participants will provide their end point information in the form and email the form to mns.registration@caiso.com. CAISO will process the information and set up the entities so the xml market event messages can be sent to the registered Market Participant end point.

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

This section is based on CAISO Tariff Sections 4.4.2, 4.4.3, 4.4.4, 4.4.5.1, 4.4.5.2, 4.4.5.3, 4.4.5.4 and 19.2

Entities that have entered into UDC Operating Agreements with CAISO must operate their Distribution Systems at all times in accordance with Good Utility Practice that ensures safe and reliable operation. The UDCs must inform their SCs of: (1) all operational information made available to UDCs by CAISO and (2) all operational information made available to CAISO by the UDCs.

UDC responsibilities include the following:

- Operate its facilities so as to avoid adverse impacts to CAISO
- Submit significant maintenance and Outage schedules with the interconnected TO and CAISO
- Coordinate electrical protective systems with CAISO
- Coordinate significant emergency system restoration with CAISO

- Maintain records of System Emergencies and maintenance
- Coordinate expansion planning, system surveys, and inspections with CAISO
- Submit Demand Forecasts to CAISO

2.4.2 Metered Subsystems

This section is based on CAISO Tariff Sections 4.9.4 and 4.9.5.

Entities that have entered into a written agreement with CAISO can participate in the CAISO Markets as MSSs. Each MSS Operator must operate its MSS at all times in accordance with Good Utility Practice that ensures safe and reliable operation. MSS Operators must inform their SCs of: (1) all operational information made available to the MSS Operator by CAISO and (2) all operational information made available to CAISO by the MSS Operators.

MSS Operator responsibilities include the following:

- Operate its facilities so as to avoid adverse impacts on the CAISO Controlled Grid
- Coordinate Generation and transmission facility maintenance and Outage schedules with interconnected PTOs and the CAISO
- Coordinate electrical protective systems with CAISO
- Maintain reliability within the MSS
- Coordinate Congestion Management and transmission line Outages within or at the boundary of the MSS
- Respond to CAISO directives during System Emergencies
- Coordinate significant system restoration with CAISO
- Maintain records of System Emergencies and maintenance
- Coordinate expansion planning, system surveys, and inspections with CAISO
- Respond to Ancillary Services Obligations
- Submit Demand Forecasts to CAISO

2.4.2.1 MSS System Unit

An MSS Operator may aggregate one or more Generating Units and/or Participating Loads as a System Unit (subject to CAISO approval). CAISO has Dispatch control over the System Unit as a whole but has control over individual Generating Units within the System Unit for Regulation purposes only.

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 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	Yes	Gross
No	Yes	Net
Yes	Yes	Net

Yes	Yes	Gross

2.4.3 Participating Transmission Owners Information

Each PTO must provide operational information to CAISO with respect to transmission facilities that have been turned over to CAISO Operational Control, including ETCs (also referred to herein as "ETCs") that are Encumbrances of the CAISO Controlled Grid.

The CAISO Tariff addresses PTOs' operational information-sharing responsibilities in Sections 4.3 and 9.

2.4.3.1 Local Reliability Criteria

CAISO operates and plans for its operation during the running of the markets, consistent with applicable Reliability Criteria set forth by NERC/WECC. In addition, CAISO operates and plans based on the Local Reliability Criteria provided to CAISO by each PTO.

Further information is provided in the *BPM for Reliability Requirements*.

2.4.3.2 Transmission Outages

This is based on Section 9 of the CAISO Tariff, in particular Section 9.3.1 (CAISO Outage Coordination Office).

The CAISO Outage Coordination Office must be notified by PTOs of all transmission facility Outages and deratings in a timely manner as described in the *BPM for Outage Management*. This information is required for reliable power system operation and optimal market operation. Reporting and CAISO approvals depend on the nature of the Outage:

- PTO planned transmission Maintenance Outage
- CAISO request for transmission Maintenance Outage
- Forced Outage
- Generator request for Maintenance Outage

Planned Maintenance Outage is assumed to occur based on the planned timeline of the approved Outage and is reflected in the market timeline subject to confirmation 72 hours in advance.

2.4.4 Participating Generators & Participating Loads

Participating Generators and Participating Loads and Demand Response providers are responsible for submitting their Outage plans in accordance with the guidelines presented in the *BPM for Outage Management*.

This section is based on Section 9 of the CAISO Tariff, in particular Section 9.3.6.

2.4.4.1 Physical Scheduling Plants

A Physical Scheduling Plant (PSP) is modeled as one individual resource, using the aggregated resource approach. The following features are available:

- Aggregated Energy constraint submitted with Bid
- Aggregated PMax and PMin submitted to Master File
- Aggregated Ramp Rate – must be updated by the Scheduling Coordinator to reflect individual unit conditions
- Aggregated Regulation service – based upon AS certification
- CAISO sends aggregated regulation signal to PSP for allocation via Generation Distribution Factors (GDFs) to the individual units

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[14], are satisfied
  - The SC for the dynamically scheduled System Resource executes an agreement with CAISO for the operation of dynamic scheduling functionality
  - 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.

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

- 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

Static data is information that is expected to change infrequently. See Attachment B of *BPM for Market Instruments*, for Master File reference 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
- 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

SCs may submit Self-Schedules for Demand or Supply for each Trading Hour of the Trading Day in addition to or without providing Economic Bids for Energy. Self-Schedules of exports are permitted. However, two different levels of schedule priorities are determined depending on if the Self-Scheduled export is explicitly being supported by energy scheduled from non-Resource Adequacy capacity or not. For a Self-Scheduled export that is explicitly supported by non-Resource Adequacy Capacity, the export has the same priority as the Self-Scheduled Demand in the Day-Ahead Market. For a Self-Scheduled export that is not explicitly supported by non-Resource Adequacy Capacity, the export is still a price taker but has a lower priority than Self-Scheduled CAISO Demand in the Day-Ahead Market. In the RTM an export can be Self-Scheduled as well. However, in the RTM, a Self-Scheduled export that is explicitly supported by Energy from either non-Resource Adequacy Capacity or Resource Adequacy Capacity that has not been committed in the RUC process has an equal priority as CAISO Forecast of CAISO Demand in the RTM. Any Self-Scheduled export that is not explicitly supported by Energy from either non-Resource Adequacy Capacity or Resource Adequacy Capacity that has not been committed in the RUC process has a lower priority than CAISO Forecast of CAISO Demand in the RTM. For PDRs and PDR-LSRs (Curtailment only), SCs can submit Energy Self-Schedules for a trading hour only if:

1) There is a Spin or Non-Spin self-provision bid for the same trading hour; and

2) The total Self-Scheduled quantity is equal to the registered Pmin of the PDR or PDR-LSR (Curtailment only).

Reliability Demand Response Resources are not allowed to submit a Self-Schedule Bid in Real-Time. Day Ahead schedules for the resource will automatically become a self-schedule for the applicable Real-Time hour. Market participant must ensure RDRR DA schedules are followed based upon notification through CMRI per BPM for Market Instruments section 5.1.3. A Self-

Schedule is modeled as an Energy Bid with an extreme price (penalty price) that effectively provides scheduling priority over Economic Bids for Energy.

SCs may also submit in the DAM only an Intertie Block Bid (i.e., a Bid from a System Resource that offers the same quantity across multiple, contiguous hours of the Trading Day). Intertie Block Bids include (in addition to the Energy Bid Curve, which can consist of Economic Bids or Self-schedules) the number of consecutive Trading Hours that any portion of the Energy Bid, which can consist of Economic Bids or Self-schedule may be accepted at the minimum. An Intertie Block Bid can either be submitted as a Self-Schedule or an Economic Bid but not as a combination of both. The particular CAISO Market process to which the Self-Schedule is submitted evaluates such Bids in terms of its scheduling priority, as described in this BPM, Section 6.6.45.3, instead of Bid price. For Settlement purposes, Self-Schedules are Price Takers:

- Self-Schedules for Supply of Energy are paid the relevant LMP as determined by the CAISO Market
- Self-Schedules for Demand of Energy are charged the relevant LMP as determined by the CAISO Market

During uneconomic adjustments, the Self-Schedules have a different priority to ETC/CVR and TOR Self-Schedules as are listed in Section 6.6.5.3, Scheduling Priorities. Refer to Section 7.5.3.2, RTM Self-Schedules and Section 7.5.3.3, Self-Schedules in HASP, for additional information.

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).

A Self-Schedule indicates that the resource is self-committed, i.e., the DAM/RTM unit commitment applications model the resource as online in the relevant intervals. A Self-Schedule, although at a higher priority than Economic Bids, may be reduced through uneconomic adjustments down to the relevant Minimum Load in the DAM/RTM if this is necessary to resolve network constraints. Self-Schedules may also be adjusted by the DAM/RTM, as necessary, to resolve any resource operational or inter-temporal constraint violations. All Self-Schedules that are Scheduled will be settled at the applicable DAM/RTM LMP.

Self-committed resources are not eligible for recovery of their Start-Up Costs for their self-commitment period. Self-committed resources are also not eligible for recovery of

their Minimum Load Costs during the intervals when they self-commit. Such resources, are however, still eligible for conditional recovery of un-recovered Bid Costs through the Bid Cost Recovery mechanism. This is described in more detail in the *BPM for Settlements and Billing, in the following configuration guides:*
(a) Pre-calculation Start-up and Minimum Loads Cost
(b) Pre-calculation IFM Net Amount
(c) Pre-calculation RUC Net Amount, and
(d) Pre-calculation RTM Net Amount

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 Reliability Capacity Bids in meeting CFBD. 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.

2.5.2.3 Self-Provided Ancillary Services

Participating Generators and Participating Loads certified for AS may self-provide those AS in the DAM/RTM. PDRs may self-provide non-spinning reserve only in DAM/RTM. A Submission to Self-Provide AS in a given Trading Hour contains only a capacity offer without a price. Submissions to Self-Provide an AS are evaluated for feasibility with respect to the relevant resource operating characteristics and regional constraints, and are then qualified (accepted) prior to AS Bid evaluation. If a regional constraint imposes a limit on the total amount of

Regulation Up, Spinning Reserve, and Non-Spinning Reserve, the Submissions to Self-Provide AS in that region may be limited, and are qualified pro rata in the following order:

- Regulation Up
- Spinning Reserve
- Non-Spinning Reserve

The process for qualifying the Submissions to Self-Provide AS is described in more detail in Section 4.2.1~~4.2.1~~. Once qualified, the Submissions to Self-Provide AS are considered Self-Provided AS, i.e., a qualified Self-Provision of AS. Self-Provided AS effectively reduces the AS requirements that need to be met by AS Bids. Self-Provided AS also reduces the AS Obligation in the AS Bid Cost allocation for the SC that Self-Provided the AS.

Qualification of Self-Provided AS indicates self-commitment [15] except for Non-Spinning Reserve Self-Provision from qualified offline resources.

PSHUs and hydro pumps may Bid or Self- Provide Non-Spinning Reserve in pumping mode up to the Pumping Level if they do not self-schedule in pumping or generating mode. Except for System Resources associated with ETC/TORs, System Resources may not Self-Provide AS (they can only submit Economic Bids for AS) because the DAM/RTM applications reserve transmission capacity for AS imports on Interties, which takes place in the optimization. The qualification process for AS Self-Provision is a pre-processing that could inevitably provide higher scheduling priority to Self-Provided AS over TOR/ETC Self-Schedules.

Refer to Section 4.2.1, Self-Provided Ancillary Services, and Section 4.2.2, Conversion of Ancillary Services to Energy in DAM, for information on qualifications of Ancillary Services with respect to RA resources.

System Resources providing a bid or self-provision of ancillary services must be certified for AS and must be capable of providing Energy in Real-Time.

2.5.2.4 Pnodes for Co-Located Resources

Pnodes for Co-located Resources utilizing the Aggregate Capability Constraint will be at their point of interconnection. Convergence Bidding Entities may submit virtual bids at this Pnode location. No congestion pricing shall result from a binding Aggregate Capability Constraint between a Co-located Resource and its point of interconnection.

[15] If the unit is committed in the IFM (DA) and the SC subsequently Self-Provides AS, e.g., in the RTM process, the RTM Self-Schedule is not considered a self-commitment.

2.5.2.5 Virtual Bids

"Convergence" or Virtual Bids are financial bids submitted only in the Day-Ahead Market. The Integrated Forward Market (IFM) clears Virtual and physical Bids in a non-discriminatory manner. If cleared in the IFM, the resulting Virtual Supply and Virtual Demand Awards would settle first at the locational Day-Ahead LMP and then be automatically liquidated with the opposite sell/buy position at the simple average of the four applicable FMM LMPs.

Convergence bidding provides Market Participants with several financial functions. First, there is the opportunity to earn revenues (and to risk losses) resulting from any differences in the Day-Ahead and FMM LMPs. Market Participants, using their insights into system and market conditions, may be able to identify Virtual Bidding opportunities that result in more efficient market outcomes. The potential for financial reward encourages Virtual Bidding activity that would tend to minimize any systematic differences between Day-Ahead and FMM LMPs, thus minimizing incentives for under or over-scheduling physical Demand in the Day-Ahead Market. A generator owner can also use a Virtual Bid to mitigate the risk impact of an outage that happens after the close of the Day-Ahead Market. By increasing market liquidity through Virtual Bidding, the potential for the exercise of market power also decreases.

Virtual Bids are explicitly flagged as Virtual Bids when submitted to the Day-Ahead Market. Their submission and processing includes an indicator that identifies them as Virtual Bids rather than physical Bids. This indication;

1) Allows for their exclusion from the automated Local Market Power Mitigation process;

2) Allows the Virtual Bids to be tracked and associated with the Convergence Bidding Entity;

3) Allows the CAISO to be able to suspend Virtual Bids by location or by Convergence Bidding Entity when necessary[16]; and

4) Allows the CAISO to exclude Virtual Bids from the RUC market.

2.5.2.5.1 Eligible Bidding Locations and Position Limits

Virtual Bids may only be submitted at certain locations. The Eligible PNode and Eligible Aggregated PNode locations may include:

- Internal Nodes (Generator and/or Load)
- Points-of-Delivery (POD)

[16] The CASO has the authority to suspend or limit Virtual Bids pursuant to Tariff Sections 7.7.15. and 7.9.

- Trading Hubs
- DLAPs (excludes CLAPs and MLAPs)

Locations that are eligible for Virtual Bid submission, except for DLAP's and Trading Hubs, are subject to Position Limits (or maximum MW Bid amounts) being enforced for those Virtual Bids submitted by SC on behalf of a single Convergence Bidding Entity (CBE). Limits are defined in the Master File by location type as specific percentages of the absolute maximum MW amount of the physical resource connected to the Eligible PNode or Eligible Aggregated PNode.

Position Limits for eligible physical supply Pnode locations will be based on the PMax of the physical resource as defined in the Master File, if the PNode is associated with a single physical supply resource, and the sum of the PMaxs of the physical supply resources as defined in the Master File, if the PNode is associated with more than one physical supply resource. Position Limits for eligible physical Demand locations will be based on the forecast of the maximum MW consumption of the physical Demand resource, if the PNode is associated with a single physical Demand resource, and the sum of the forecast of the maximum MW consumption of the physical Demand resources, if the PNode is associated with more than one physical Demand resources.

In the case where both physical supply and physical Demand resources are connected to an Eligible PNode or Eligible Aggregated PNode within the CAISO Balancing Authority Area, the greater of the two resources (either supply or Demand) is used as the basis for calculating the applicable Position Limit.

Refer to Tariff sections 30.7.3.6.3 for information on Position Limit settings.

CAISO will report the Eligible PNode and Eligible Aggregated PNode locations and their maximum MW limits in OASIS. Please refer to the *BPM for Market Instruments* for additional information.

2.5.3 Inter-SC Trades

CAISO facilitates Inter-SC Trades (IST) of Energy, Ancillary Services and IFM Load Uplift Obligation through the Settlement process. There are two types of IST of Energy. Physical Trades (PHY) which are ISTs at individual PNodes of Generating Units within the CAISO Balancing Authority Area that are backed by a physical resource at that Location and Inter-SC Trades at Aggregated Pricing Nodes (IST APN), which do not require the SC to identify the specific physical resource that is backing the trade. Each AS can be traded through IST as can the IFM Load uplift obligation. Inter-SC Trades are financial and do not have any physical impact on the market optimization solution. They are further described in Section 9 of the *BPM for Market Instruments*.

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

Existing Transmission Contracts, Transmission Owner Rights, and Converted Rights are described in Section 5 of this BPM.

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 non-generating 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 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 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 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

The provisions in this sub-section describe the process for establishing Monthly and Daily Wheeling Through Priority under section 23 of the tariff. Scheduling Coordinators can reserve Available Transfer Capability (ATC) in advance across the CAISO interties to establish Wheeling Through Priority for scheduled market transactions. An ATC reservation is not required to wheel through the CAISO transmission system, and such transactions will be treated as non-priority wheel through transactions.

Calculating Available Transfer Capability (ATC) and Supporting Data Submissions

To establish Wheeling Through Priority, a Scheduling Coordinator must reserve ATC on the CAISO interties in advance in monthly or daily increments. Monthly ATC is calculated across a rolling 13-month horizon; daily ATC is calculated across a rolling 7-day horizon. ATC for establishing Wheeling Through Priority is calculated on both the import and export interties. The calculation of ATC across these time horizons is described in Appendix L-1 of the Tariff and within the ATC Implementation Document.

To support the calculation of ATC and the determination of the native load need (NLN) component of the methodology, the CAISO relies on historical information of import supply contracted to serve load on specific interties shown on monthly Resource Adequacy (RA) plans and those that were not identified on RA plans. The historical information considers the prior two years of contracted RA imports and non-RA imports on each intertie.

CAISO load serving entities (LSEs) currently provide, and have historically provided, monthly RA plans, which identify contracted import supply to serve their load. The CAISO has not historically collected LSE information on contracted import supply dedicated to serve load that is not shown on RA plans. To support the calculation of the NLN component, CAISO LSEs that contracted import supply to serve load which was not shown on RA plans can submit that information to the CAISO to support the calculation through the Customer Interface for Resource Adequacy (CIRA) interface. The monthly NLN submission window is open for fourteen (14) days each month, with the closure of the window coinciding with the closure of the CAISO monthly Resource Adequacy plan submission cure period under Section 40 of the tariff.

As described in section 23.3.2 of the Tariff, CAISO LSEs may provide the historical non-RA contracted import information for the last two years (in monthly increments), if available and applicable, identifying the firm supply contracts that are longer than one month in duration. These would include contracts in effect for the applicable month, monthly contracts for the applicable month, or a portfolio of shorter-term contracts for the applicable month. The information provided should include identification of the intertie name, the MW quantity, and the

duration of the contract term. The data associated with historical import supply contracts should be updated monthly to ensure that it is available when calculating monthly ATC across a rolling 13-month horizon, particularly as monthly ATC is calculated for the new month in the rolling horizon.

Under section 23.3.3 of the tariff, the CAISO may also set aside transmission capacity as part of NLN for new import supply contracts for a month that is thirteen (13) months away when calculating monthly ATC (first time that ATC is calculated for a month). The CAISO LSE should notify the CAISO of the new firm supply import contract to serve their load through identification in CIRA that are not otherwise reflected in historical data. The LSE must attest whether the new import supply contract replaces a contract shown on historical import supply procurement submissions or is a new incremental supply contract and provide information on the start and stop date of the new import supply firm contract, the specific hours across which the contract applies, the MW quantity, and the import scheduling point on the CAISO system. Similarly, to the extent the new import supply contract is a replacement contract of import supply previously shown or captured in the historical data, the LSE must attest to and indicate the prior contract is being replaced. The LSEs must also notify the CAISO of import contracts submitted as part of and reflected in historical data that will end during the thirteen month horizon across which the CAISO calculates monthly ATC and will not be replaced with another import contract at the same import scheduling point.

Per tariff section 23.3.4, a Load Serving Entity may show to the CAISO any firm non-Resource Adequacy contracts it has for the upcoming RA month in which RA submissions are open that should be considered in the ATC calculation.

The CAISO will use the contracted import supply information to determine the existing transmission commitments (ETComm), including the NLN component, of the ATC calculation under Appendix L-1 of the tariff.

ATC, and related component data across the monthly and daily calculated horizons is published on the CAISO OASIS.

2.5.5.2.3(b) Establishing monthly and daily Wheeling Through Priority

Scheduling Coordinators can establish monthly and daily Wheeling Through Priority through the submission of a request to reserve monthly and daily ATC. Requests for ATC are submitted by Scheduling Coordinators via the new WebWheel interface, which allows for meeting the requirements under section 23 of the tariff.

2.5.5.2.3(b)(1) Monthly Requests for ATC

Scheduling Coordinators may submit requests for monthly ATC during a request window consistent with Section 23.4 of the Tariff to establish Wheeling Through Priority. Monthly ATC for Wheeling Through Priority is calculated across a rolling 13-month horizon and requests can be submitted to reserve ATC across that horizon as published on the CAISO OASIS.

Submitting a Request for Monthly ATC

Requests for monthly ATC are submitted via the WebWheel interface. Scheduling Coordinators can request monthly Wheeling Through Priority through the submission of a request for ATC for any month or months calculated across the 13-month horizon.

To submit a request for monthly ATC, the Scheduling Coordinator must provide:

- Intertie point of receipt (POR) on the CAISO system and the intertie point of delivery (POD).
- MW quantity of the request
- Start and stop dates of the request
- Underlying supporting firm supply contract information (including contract hours)
- Identification of willingness to accept partial service

The Scheduling Coordinator request for Wheeling Through Priority through the request for ATC must be supported by an executed firm power supply contract to serve an external load serving entity's load, a firm power supply contract to serve an external load serving entity's load where execution is contingent upon the availability of a Wheeling Through Priority on the CAISO system, or the external load serving entity's ownership of an external resource to serve external load. The Scheduling Coordinator will identify the MW quantity of the firm power supply contract supporting the submission of the request, the start and end date of the contract along with the specific hours during the month covered by the supply contract for which are seeking Wheeling Through Priority consistent with section 23.2.1 of the tariff.

A Scheduling Coordinator submitting the request can also identify whether they are willing to accept partial service. Within the request submission interface, the Scheduling Coordinator can identify whether they are willing to accept an award of ATC that is lower MW amount than requested and/or lower duration than requested.

The Scheduling Coordinator submitting the request is further required to attest, through the WebWheel interface, that the information submitted in the request, including the representations about the firm supply contract, are true and accurate and consistent with section 23 of the tariff.

Monthly ATC Request Submission Windows

The monthly ATC request window is open for fourteen (14) days each month, with the closure of the window coinciding with the closure of the CAISO monthly Resource Adequacy plan

submission cure period under Section 40 of the tariff. The monthly ATC request windows are posted for the calendar year on the Reliability Requirements webpage.

Requests submitted during the window are treated as having been submitted simultaneously and are evaluated together for ATC. Requests for monthly ATC must be supported, at a minimum, by a six (6) day by four (4) hour firm supply contract for the month where ATC is requested. Once submitted, the requests will be evaluated together for ATC and to the extent that there is not sufficient ATC to accommodate all the submitted requests these will be competed for ATC based upon the underlying duration of supporting supply contract hours across the requested period. Thus requests for monthly ATC supported by a supply contract of a longer duration of contract hours across the months for which ATC is requested will be awarded ATC ahead of requests with fewer supply contract hours. For example, a monthly ATC request seeking to establish Wheeling Through Priority for one (1) month supported by a supply contract of six (6) days by sixteen (16 hours) will be awarded ahead of a request for one (1) month supported by a six (6) days by eight (8) hours per week firm supply contract. Similarly, a monthly ATC requests for five (5) months supported by a six (6) by eight (8) hours supply contract will be awarded ahead of a request with a power supply contract for just one of those months with a six (6) by eight (8) hours contract. If there is a tie among the request based on the evaluation described above, the ATC and Wheeling Through Priority will be allocated on a pro-rata basis to the extent the requests made the indication of willingness to accept partial service.

The CAISO will evaluate the requests and make the determination of monthly Wheeling Through Priority awards based on the ATC assessment of the request no later than three (3) Business Days after the request window closes.

2.5.5.2.3(b)(2) Daily Requests for ATC

Scheduling Coordinators may submit requests for daily ATC during a request window consistent with Section 23.5 of the Tariff to establish Wheeling Through Priority. Daily ATC for Wheeling Through Priority is calculated across a rolling 7-day horizon and requests can be submitted to reserve ATC across that horizon as published on the CAISO OASIS.

Submitting a Request for Daily ATC

Requests for daily ATC are submitted via the WebWheel interface. Scheduling Coordinators can request daily Wheeling Through Priority through the submission of a request for ATC for any day or days calculated across the 7-day horizon.

To submit a request for monthly ATC, the Scheduling Coordinator must provide:

- Intertie point of receipt (POR) on the CAISO system and the intertie point of delivery (POD).
- MW quantity of the request
- Start and stop dates of the request
- Underlying supporting firm supply contract information (including contract hours)
- Identification of willingness to accept partial service

The Scheduling Coordinator request for Wheeling Through Priority through the request for ATC must be supported by an executed firm power supply contract to serve an external load serving entity's load, a firm power supply contract to serve an external load serving entity's load where execution is contingent upon the availability of a Wheeling Through Priority on the CAISO system, or the external load serving entity's ownership of an external resource to serve external load. The Scheduling Coordinator will identify the MW quantity of the firm power supply contract supporting the submission of the request, the start and end date of the contract along with the specific hours across the day covered by the supply contract for which are seeking Wheeling Through Priority consistent with section 23.2.1 of the tariff.

A Scheduling Coordinator submitting the request can also identify whether they are willing to accept partial service. Within the request submission interface, the Scheduling Coordinator can identify whether they are willing to accept an award of ATC that is lower MW amount than requested and/or lower duration than requested.

The Scheduling Coordinator submitting the request is further required to attest, through the WebWheel interface, that the information submitted in the request, including the representations about the firm supply contract, are true and accurate and consistent with section 23 of the tariff.

Daily ATC Request Submission Windows

The daily ATC request window is open for five (5) hours during the hours of X to X every day across the rolling 7-day horizon for which daily ATC is calculated. The monthly ATC request windows are posted for the calendar year on the Reliability Requirements webpage.

Requests submitted during the window are treated as having been submitted simultaneously and are evaluated together for ATC. Requests for daily ATC must be supported by a firm power supply contract of at least four (4) hours for each day during the seven (7)-day horizon for which the Scheduling Coordinator seeks the Wheeling Through Priority. Once submitted, the requests will be evaluated together for ATC and to the extent that there is not sufficient ATC to accommodate all the submitted requests these will be competed for ATC based upon the underlying duration of supporting supply contract hours across the requested period. Thus

requests for monthly ATC supported by a supply contract of a longer duration of contract hours across the day(s) for which ATC is requested will be awarded ATC ahead of requests with fewer supply contract hours. For example, a daily ATC request seeking to establish Wheeling Through Priority for one day supported by a supply contract of six (6) days by sixteen (16 hours) will be awarded ahead of a request for one day supported by a six (6) days by eight (8) hours firm supply contract. Similarly, a daily ATC requests for five (5) days supported by a six (6) by eight (8) hours supply contract will be awarded ahead of a request with a power supply contract for just one of those days with a six (6) by eight (8) hours supply contract. If there is a tie among the request based on the evaluation described above, the ATC and Wheeling Through Priority will be allocated on a pro-rata basis to the extent the requests made the indication of willingness to accept partial service.

The CAISO will evaluate the requests and make the determination of daily Wheeling Through Priority awards based on the ATC assessment of the request no later than two (2) hours after the daily request window closes.

2.5.5.2.3(b)(3) Termination or Modification

Consistent with section 23.2.3 of the tariff, if the firm power supply contract supporting the Wheeling Through Priority across a monthly or daily horizon is terminated or modified such that the MW quantity, hours of service, import or export point changes, the Scheduling Coordinator must notify the ISO within the earlier of (i) five (5) Business Days after the effective date of the termination or (ii) eleven (11) Business Days before the start date of the priority under the awarded request.

If the supporting firm supply contract is terminated eleven (11) or more Business Days prior to the date on which the awarded ATC and Wheeling Through Priority transaction can be scheduled, the Wheeling Through Priority will terminate unless the Scheduling Coordinator can demonstrate an equivalent replacement power supply contract by the earlier of (i) sixty (60) days from the date of termination of the supply contract or (ii) eleven (11) Business Days prior to the date for which the ATC and Wheeling Through Priority can be exercised under the awarded priority. If the Scheduling Coordinator will not seek to replace the terminated firm supply contract, it must notify the CAISO within five (5) Business Days of that decision, but no later than eleven (11) Business Days before the date any Wheeling Through Priority can be scheduled. In these circumstances, the ATC held for Wheeling Through Priority will be released for reservation and use by other market participants and the Scheduling Coordinator will not be assessed charges.

If the firm supply contract supporting the established Wheeling Through Priority (through reserved ATC) is terminated or modified after eleven (11) Business Days before the Day Ahead Market run for the date on which the Wheeling Through Priority can first be schedule, the Scheduling Coordinator will retain the Wheeling Through Priority and will continue to be charged for the priority for the duration of the ATC reservation.

Submissions of updates to the firm supply contract supporting the awarded ATC and established Wheeling Through Priority occur via the WebWheel interface. Within the submission, the Scheduling Coordinator will identify the reason for the termination or modification of the underlying firm supply program and attest to the information provided.

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

The CAISO will post ATC information on OASIS for both the monthly ATC 13-month rolling horizon and the daily ATC 7-day rolling horizon consistent with the ISO tariff. The CAISO will post ATC available for reservation for establishing Wheeling Through Priority in both the import and export direction to support submission of a request for ATC. In addition to ATC, the CAISO will post the individual components applicable to the calculation of ATC consistent with the equation under Appendix L-1 of the ISO tariff.

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

Under section 23.8.1 of the CAISO tariff, a Scheduling Coordinator may resell monthly Wheeling Through Priority based on reserved ATC. The Wheeling Through Priority Reseller with a monthly Wheeling Through Priority may resell all or a portion of the MW quantity of its Wheeling Through priority for the month(s), remainder of the month or term, to another Market Participant (assignee). The Wheeling Through Priority Reseller must notify the CAISO by 8 days from the effective date of the resale to allow the CAISO time to make the necessary associations to support the ability of the assignees to schedule the Wheeling Through Priority. The resale must be at the same import Scheduling Point as the original Wheeling Through Priority, but it may be at a different export Scheduling Point if the CAISO can accommodate such a change and maintain the status of the Wheeling Through Priority.
The Wheeling Through Priority Reseller will notify the CAISO of the resale and associated information through the WebWheel interface. It will identify the reseller and assignee, term of the resale, and price, which will be posted on the CAISO OASIS page.The Assignee must also confirm the resale in WebWheel, after the reseller reports it, for it to take effect.

The Wheeling Through Priority Reseller cannot resell a priority MW amount more than the underlying established Wheeling Through Priority (based on awarded ATC) or for a longer term

than established through the reservation of ATC. The Scheduling Coordinator may not resell daily Wheeling Through Priority.

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

In order to exercise Wheeling Through Priority, the Scheduling Coordinator must register import and export resources in the CAISO Master File prior to scheduling the wheel through across the CAISO system. The registration of the import/export resource enables the CAISO to recognize the Wheeling Through Priority in the market.

The Scheduling Coordinator should submit a Master File request, including the Scheduling Coordinator ID and related information, to register import/export resource IDs that will be used to support the Wheeling Through Priority. This registration of import/export IDs should be done in advance of the submission of a request for ATC.

The Scheduling Coordinator will need to register a supporting supply contract in WebWheel that will facilitate submission of requests for monthly and daily ATC.

A Scheduling Coordinator can pre-register import/export resource IDs to support later submission of requests for monthly and daily ATC.

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

2.5.6 Real-time Price during tight system conditions

When the CAISO declares a system emergency, the CAISO likely anticipates or is undergoing an energy deficiency at either local or system levels. In such cases, CAISO system operators may ask utilities to arm load to cover operating reserve obligations, then use the market software to dispatch the operating reserves for use as energy.

For the specified operating reserve deficiency, CAISO operators may trigger all spin and non-spin, and non-spin to release both contingent and non-contingent operating reserves at the

applicable energy bid cap. The CAISO will only do so when it has exhausted all available energy supply bids. This will appropriately signal the tight supply condition.

2.5.7 Reliability Demand Response Dispatch and Real-time Price

Reliability Demand Response Resources (RDRRs) are intended to be used immediately prior to or during emergency conditions, at the discretion of CAISO system operators.
RDRR resources can be registered as 5-minute, 15-minute, or 60-minute dispatchable resources.

- Resources registered as 15-minute dispatch will be allowed to set the marginal energy price in the fifteen-minute market whether registered as continuous or discrete.
- Resources registered as 5-minute dispatch will be able to set the marginal energy price in RTD.
- Resources registered as 60-minute dispatch that clear in HASP will receive a fifteen-minute market schedule and will be settled at the corresponding locational marginal price during each fifteen-minute market interval.

The CAISO will take additional, automated actions in its bidding systems to prevent infeasible dispatch of discrete RDRRs as explained below.

- When a discrete RDRR bid is submitted, the CAISO will automatically adjust the discrete RDRRs' Pmin to a value of 0.01 MW below the resource's Upper Economic Limit (UEL) per the following formula:

  Pmin Re-Rate = UEL – 0.01 MW

- In addition to the above, the Minimum Load Cost (MLC) bid of the discrete RDRR will automatically be calculated using the following formula:

  Adjusted MLC = Original MLC + (One-Segment Bid Price) * (Pmin Re-rate)

- Example: a discrete RDRR with a Pmin of 0 MW submits an energy bid of $950/MWh at 6 MW. Assume the original MLC is $0/hour.
  - Pmin Re-Rate = 6 MW – 0.01 MW = 5.99 MW
  - Adjusted MLC = 0 + ($950/MWh * 5.99 MW) = $5,690.5/hour
  - The market will view the re-rated Pmin as the RDRR's Pmin in real-time.
  - The adjusted MLC will be considered as the RDRR's commitment costs.
  - If committed, the RDRR could be dispatched to 5.99 MW (re-rated Pmin) or 6 MW (bid).
  - If the RDRR is dispatched in rea-time, its re-rated Pmin and adjusted MLC will be eligible for Bid Cost Recovery (BCR) consideration if the RDRR is short over the course of the day.
    - Note: A cleared Economic Hourly Block Bid is not eligible for Bid Cost Recovery. For more information, see Section 11.6.4 of the Tariff.

When RDRR is enabled, it will behave as follows;

Dispatch Option	DISCRETE?	RTPD	RTD
Hourly	Y	Optimal commitment on hourly block and cleared at pre-specified level	Matching RTPD MW
Hourly	N	Optimal commitment on hourly block and cleared between Pmin and Pmax	Matching RTPD MW
15-min	Y	Optimal commitment and cleared at pre-specified level	Matching RTPD MW
15-min	N	Optimal commitment and cleared between Pmin and Pmax	Matching RTPD MW
5-min	Y	Optimal commitment and cleared at pre-specified level	Matching RTPD MW
5-min	N	Optimal commitment and cleared between Pmin and Pmax	Respect commitment but re-optimize MW

Additionally, the dispatched RDRR quantity will be added to the load forecast for future intervals for the duration of time RDRRs are dispatched.

2.5.8 Minimum state of charge (MSOC)

The minimum state of charge (MSOC) was developed as a temporary tool for storage management to ensure that in the real-time market, storage resources are charged to a level that will allow them to deliver their day-ahead discharge schedules.

This tool will only be triggered on days when the residual unit commitment process results in an under-generation infeasibility at any trading hour. Furthermore, the MSOC will be enforced in the real-time market only during a specified window of critical hours, and any hours leading to that window if the storage resource needs to charge to attain the required SOC. There is no additional market compensation beyond the regular energy settlement and applicable bid cost recovery to storage resources that may be subject to the minimum state of charge.

2.5.9 Sustained Energy Requirements for Storage Resources with Regulation Awards

The CAISO tariff section 8.4.1.1 requires that all resources awarded regulation are able to respond quickly and accurately to automatic generator control (AGC) signals from the CAISO, and respond to signals consistently for the period corresponding to the award. This implies that storage resources providing regulation must have sufficient energy (i.e., SOC) to respond to automatic generator control signals, including periods when a storage resource receives regulation up or regulation down awards.

Storage resources are fundamentally different from traditional gas resources in that they are unable to generate energy but instead store energy and move it from one time of the day to another. This works well in the CAISO system where energy tends to be abundant during the

middle part of the day when solar is available but stretched thin during evening peak periods when renewables contribute very little and load is high.

A model for storage resources was developed to allow tracking of state of charge (SOC), positive (discharge), and negative (charge) dispatch instructions. This is to ensure storage resources in RTD, RTPD, and RTCD have sufficient SOC to support regulation up and regulation down awards for a user-configurable amount of time in real-time market.

For regulation up and regulation down awards, the user-configurable sustained energy delivery time defaults to the following:

RTPD	30 min
RTD	30 min
1st RTCD	20 min
2nd RTCD	10 min

Storage resources must hold enough state of charge so that they will be able to respond to regulation signals at the awarded level for the configurable amount of time in the real-time market. This implies that if a storage resource receives a 10 MW award for regulation up, they will have at least 5 MWh of state of charge, assuming the default configurable sustained energy time. Similarly, if the storage resource receives a 10 MW award for regulation down, they will be required to hold no more state of charge than 5 MWh below their maximum state of charge.

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)[17] are also described in the BPM.

3.1 Model Description

FNM is comprised of a detailed model of the physical power system network along with an accurate model of commercial network arrangements. These arrangements reflect the commercial scheduling and operational practices to ensure that the resulting LMPs reflect both the physical system and the schedules produced by the market applications.

The CAISO markets employ a FNM with an accurate representation of the CAISO Balancing Authority Area and embedded and adjacent Balancing Authority Areas. The CAISO enforces both scheduling and physical constraints at each CAISO Intertie to reflect:

a) The scheduling constraint that constrains the physical Energy and Ancillary Services Bids from scheduling hubs when these Bids declare the respective Intertie for schedule tagging; there are no shift factors used in these constraints. Both physical and Virtual Bids will be considered in this constraint in the Integrated Forward Market. Only physical schedules will be considered in the Residual Unit Commitment.

b) The physical flow constraint that constrains the schedule contributions from all physical and Virtual Energy Bids inside and outside of the CAISO Controlled Grid; shift factors are used in these constraints. Both physical and Virtual Bids will be considered in this constraint in the Integrated Forward Market. Only physical schedules will be considered in the Residual Unit

[17] 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.

Commitment. The scheduling and physical constraints are limited by the same operational limit of the Intertie.

The FNM is composed of network Nodes[18] (henceforth CNodes) interconnected with network branches. Generating Units and Loads are modeled at the relevant CNodes. A subset of CNodes is selected to be Pricing Locations (PNodes).

A PNode is identified as a CNode at which LMPs are calculated, i.e, for each resource and substation. Each PNode is associated with a single CNode in the network model. As used in the Reference Data Requirements documentation on the CAISO website, CAISO has groupings of CNodes that are used in the running of the CAISO Markets, including the CAISO system, Balancing Authority Areas, RUC zones, and Load forecast zones. This is different than the Aggregated Pricing Nodes (APNodes, which are groupings of PNodes used to consolidate the bidding and pricing of physical and Virtual Supply and Demand in the CAISO Markets).

Import and export resources are modeled as System Resources at the CNodes at the external end of interties with other Balancing Authority Areas (i.e. Scheduling Points). Aggregate Generating Units and Loads are modeled as individual physical resources in the FNM, and their Energy Supply and Demand is then mapped to their associated physical resources in the FNM using the relevant Generation and Load Distribution Factors, respectively.

For the IFM only, Virtual Awards are modeled as new objects dynamically created internal to the power flow application. These new objects are referred to as virtual injections. These virtual injections are created at all locations where there are Virtual Awards, whether or not physical Supply or physical Demand objects exist at these locations. In the case where Virtual Awards are co-located with physical Demand or Generation, the virtual injection will be a separate object and the MW value of the virtual injection will not be mapped to the MW value of the physical injection.

To the extent sufficient data is available or adequate estimates can be made for the Integrated Balancing Authority Areas, the CAISO may use this data for power flow calculations and Congestion Management in the CAISO Markets Processes. CAISO monitors but does not enforce the network constraints for Integrated Balancing Authority Areas in running the CAISO Markets Processes. CAISO models the resistive component for Transmission Losses on Integrated Balancing Authority Areas but does not allow such losses to determine LMPs.

[18] The CAISO BPMs have adopted "Connectivity Node" or CNode as an alternative expression of "Node". Aggregated PNodes are also referred to as "APNodes".

The use of the FNM in the DAM and the RTM incorporates Transmission Losses and allows modeling and enforcing all network constraints. This results in LMPs for Energy that reflects the System Marginal Energy Cost (SMEC), Marginal Cost of Losses (MCL), and Marginal Cost of Congestion (MCC). Although the SMEC component of the LMP is the same for all PNodes, based on the selection of a certain Reference Bus, the MCL and the MCC may vary across the network due to network characteristics and power flow patterns.

3.1.1 Real-Time Data

The following Real-Time data are passed from the Energy Management System (EMS) and the State Estimator (SE) to the Real-Time Market (RTM):

Exhibit 3-1: Generator Telemetry Data from EMS to RTM

Variable	Comment
Unit ID	Generating Unit Identification
Unit Telemetry	Actual MW amount of Power produced
Reg Flag	Unit's Regulation Status (Y = Active) (N = Not Active)
Max Op Limit	Maximum Operating Limit [MW]
Min Op Limit	Minimum Operating Limit [MW]
Unit Online	Unit's Online Status (Y = On Line) (N = Off Line)
Quality Tag	Unit's Data Quality (1 = Good) (2 = Bad) (3 = Manual Override)

Exhibit 3-2: Load Telemetry Data from EMS to RTM

Variable	Comment
Load ID	Load Identification
Load Telemetry	Actual MW amount of Power consumed
Quality Tag	Load's Data Quality (1 = Good) (2 = Bad) (3 = Manual Override)

Exhibit 3-3: Connectivity Node Data from SE to RTM

Variable	Comment
CNode ID	Connectivity Node Identification (Load or Generator)
MW Level	State Estimator MW (Load or Generator)
Connection	"C" for Connectivity

3.1.2 Generation Distribution Factors

SCs may submit single Bids for multiple Generating Units at an APNode (Physical Scheduling Plant and System Unit) or individual Bids for individual Generating Units at individual PNodes, depending on how the Generating Units are registered with CAISO. An APNode is associated with a designated set of PNodes. Supply Bids and Self-Schedules that are submitted for the Aggregate Generating Resource at an APNode are distributed by CAISO to the associated individual PNodes according to a set of Generation Distribution Factors (GDFs), consisting of factors and location names that must also be submitted with the Bid. These GDFs are automatically re-normalized in the CAISO Market applications to account for any Generating Unit Outages.

SCs may provide GDFs for its Aggregate Generating Resources with its bid, otherwise the Market Applications will use default GDFs from the GDF Library. The submitted GDFs should reflect actual conditions and should be submitted as normalized values (summing up to 1.0).

Aggregated Generating Resources must be registered and approved by CAISO. CAISO evaluates the extent to which the individual resources share a common fuel supply and how they are physically located on the grid. The evaluation of whether a generator is allowed to be part of an Aggregate Generating Resource is generally performed during the CAISO's generator interconnection process. Refer to CAISO website for details:

http://www.caiso.com/docs/2002/06/11/20020611103004272l4.html

The CAISO Market applications optimally commit and schedule Aggregate Generating Resources based on their aggregate Bids and their aggregate location. The aggregate schedules are decomposed using the relevant GDFs to individual physical unit schedules for power flow calculations in the Full Network Model.

Virtual Supply Bids at the Aggregated PNode locations will have the GDF applied just as physical Supply Bids thereby treating physical and Virtual Bids consistently in the Day-Ahead Market.

The LMP for an Aggregate Generating Resource is calculated after Market Clearing as the weighted average of the LMPs at the PNodes associated with the individual Generating Units comprising the Aggregate Generating Resource, using the relevant GDFs as the weighting factors.

3.1.3 Modeling Point

Exhibit 3-5 illustrates another type of APNode, where the model consists of one or more Generating Units supplying Power to the CAISO markets.

The Point of Receipt of a Generating Unit is established by technical information provided by the Generator and Transmission Owner during the CAISO's Generation interconnection process or based on existing information. The Point of Receipt may be different from the physical location (CNode) where the Generating Unit is connected. The FNM represents the Generating Unit at its actual physical location, and computes loss factors from that location to the contractual Point of Receipt. Settlement is based on deliveries to the Generating Unit's Point of Receipt, and uses the LMP at such point.

In general, the pricing Location of a Generating Unit coincides with the CNode where the relevant revenue quality meter is connected or corrected, to reflect the point at which the Generating Units are connected to the CAISO Controlled Grid. This Location is referred to as the PNode. Although the schedule, Dispatch, and LMP of a Generating Unit refers to the PNode, the Energy injection is modeled in the FNM for network analysis purposes at the corresponding Generating Unit(s) (at the physical interconnection point), taking into account any losses in the transmission network leading to the point where Energy is delivered to Demand.

The CAISO model generates prices at both modeling points (Point of Receipt and Cnode) when a resource has a Point of Receipt that differs from its physical location. The energy prices can differ due to the losses between the two modeling points, reflected in different marginal loss cost component in the LMP. Thus, the difference between where the energy injection is modeled in the FNM (CNode) and the settlement location (POR) of the resource can result in cases where the resource may appear to be dispatched uneconomically when comparing its bid to the energy price used for settlement purposes. This is because the FNM models the injection of the energy at the physical location of the resource, considering the marginal cost of losses at that location, and then calculating the marginal cost of losses at the settlement location. When determining which resource is economical to dispatch or curtail, the market "sees" the bids and cost at the physical location of the resource, not the location used for settlement purposes.

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 BAA Demand (CFBD) 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 CFBDin 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.

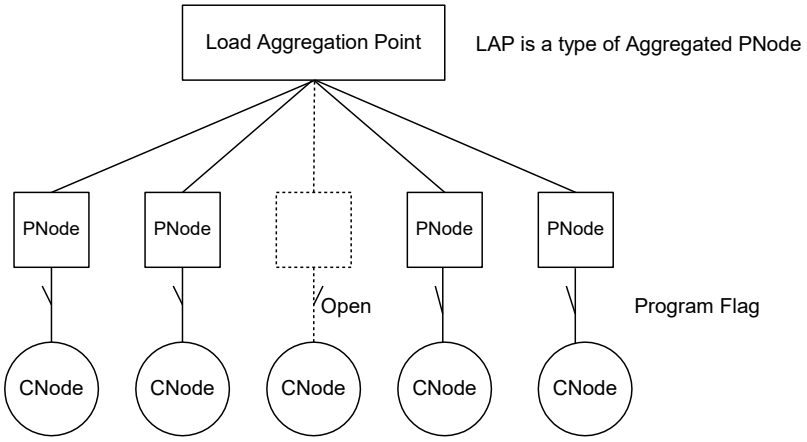
CAISO also maintains a set of Load Aggregation Factors (LAFs) in the Master File for each Default or Custom LAP. These LAFs represent the percentage sharing of load at the CNode among different overlapping LAPs.

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.

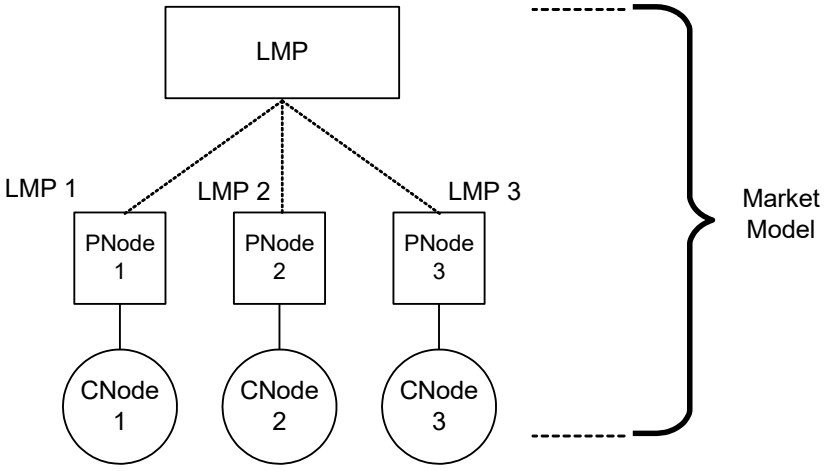
Exhibit 3-4 illustrates the model of a LAP.

Exhibit 3-4: Load Aggregation Point



CNode = Connectivity Node
PNode = Pricing Node

Exhibit 3-5: Modeling Point



3.1.5 Aggregated Pricing Nodes

Aggregated Pricing Nodes (APNodes) are aggregations of Pricing Nodes as defined by CAISO which include LAPs and Trading Hubs.

The CAISO Market applications calculate LMPs and their components for all PNodes and APNodes, and all resources, including aggregate resources. The LMP of a resource is the LMP of the corresponding Location, aggregate or not. LMPs for Aggregate Generating Resources and aggregate Non-Participating Loads are calculated as weighted averages of the LMPs at the relevant PNodes, weighted by the relevant GDFs and LDFs. Note that since the distribution of the aggregate Energy schedules for aggregate resources is fixed and based on the relevant GDFs and LDFs, the weights are also equal to the relevant normalized individual Energy Schedules for these resources. For LAPs the prices are derived directly from the optimization based on the effectiveness of the total aggregation on reliving congestion, within the effectiveness threshold specified in section 6.6.5.

Aggregate LMPs are also calculated for Trading Hubs, which are defined as APnodes. Trading Hub LMPs are used for the Settlement of CRRs and Inter-SC Trades of Energy, other than physical Inter-SC Trades of Energy. The weights applied to the constituent nodal LMPs in each Existing Zone Generation Trading Hub are determined annually and separately for each season and on-peak and off-peak period based on the ratio of the prior year's total output of Energy at that PNode to the total Generation output in that Existing Zone, for the corresponding season and on-peak or off-peak period. Trading Hub prices are derived directly from the optimization based on the effectiveness of the resource as an aggregate if the effectiveness of the aggregate resource is at or above the effectiveness threshold specified in section 6.6.5.

The CAISO Market applications also calculate the Shadow Prices of all binding network constraints and scheduling constraints at the optimal solution. The Shadow Prices contribute to the Marginal Cost of Congestion component of the LMPs. Furthermore, the Shadow Prices at Scheduling Points are used in used in Settlement to calculate explicit Congestion charges to Ancillary Services Imports.

3.1.6 Losses

There are two types of losses:

- **Transmission Losses** – also referred to as actual losses
- **Marginal Losses** – also referred to as incremental losses

Both actual and Marginal Losses are generally higher when Generation or imports are far away from CAISO's major Load centers and losses are lower when Generation is close to the Load centers. Both the actual MW losses and the Marginal Losses depend on the resistance of branches in the network, which depends in turn on factors including the length and conductor type of transmission lines, and transformer characteristics, and the MW loading and voltage profile of the Transmission network.

3.1.6.1 Transmission Losses

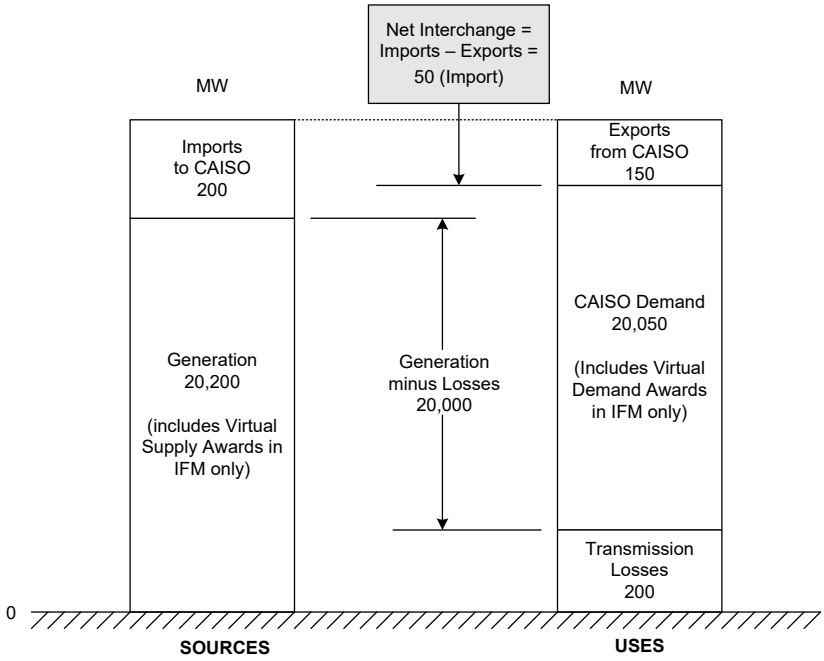
Transmission Losses are the Energy that is lost as a natural part of the process of transmitting Energy from Generation to Load delivered by CAISO at the UDC, MSS, or Balancing Authority Area boundary.

For example, if the total Power delivered to all the boundaries is 20,000 MW and the total CAISO Generation is 20,200 MW, then the Transmission Losses equal to 20,200 MW minus 20,000 MW or 200 MW.

The FNM is an AC network model that includes the effect of Transmission Losses within the CAISO Balancing Authority Area. The SCUC/SCED applications optimally adjust resource Schedules to cover Transmission Losses. In other words, the final CAISO Market Energy Schedules for Supply exceeds the corresponding Energy schedules for Demand and exports by the amount of Transmission Losses in the CAISO Balancing Authority Area.

Exhibit 3-6 shows the Power balance relationship for the CAISO Balancing Authority Area and illustrates the above Transmission Losses example. In the IFM, Virtual Demand and Supply Awards are included in the Power balance equation.

Exhibit 3-6: CAISO Power Balance Relationship



For the Non-Participating Transmission Owner (NPTO) network, transmission losses will be calculated and assessed based on governing contractual arrangements if any exist, or any Transmission Ownership Rights contractual arrangements presented to the CAISO and the location of the Energy injection.

3.1.6.2 Marginal Losses

Marginal Losses are the transmission system incremental real power losses that arise from changes in Demand at a CNode that is served by changes in is the distributed Load reference as further described in the *BPM for Managing Full Network Model*.

For example, if we increase the Demand by 1.0 MW at CNode X and observe that the distributed Load reference must increase its output by 1.1 MW to serve this Demand increase, then the Marginal Losses with respect to CNode X is equal to 1.1 MW minus 1.0 MW or 0.1 MW.

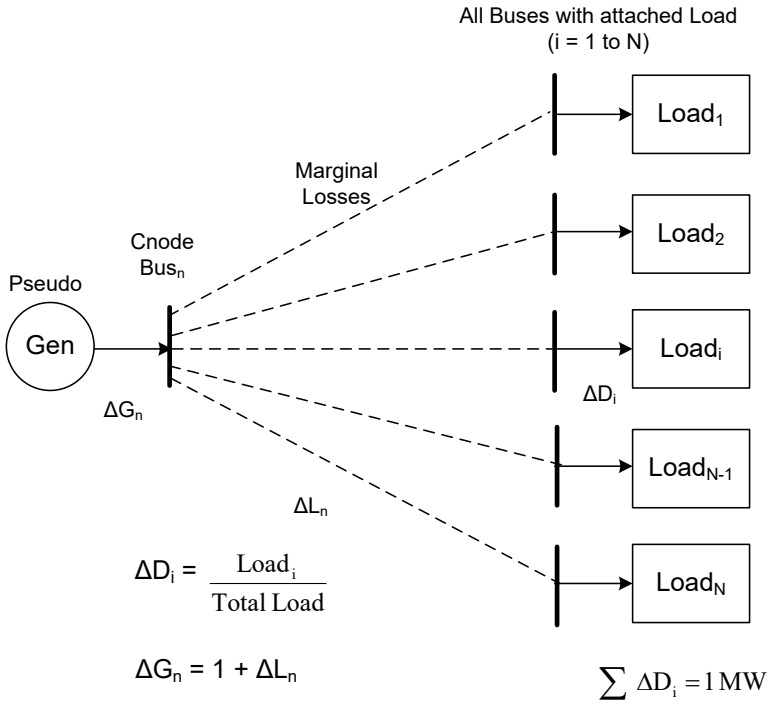
The corresponding Marginal Loss Factor for CNode X is equal to the Marginal Losses for Node X divided by the increase in Demand at CNode X, in this example (0.1 MW / 1.0 MW = 0.1).

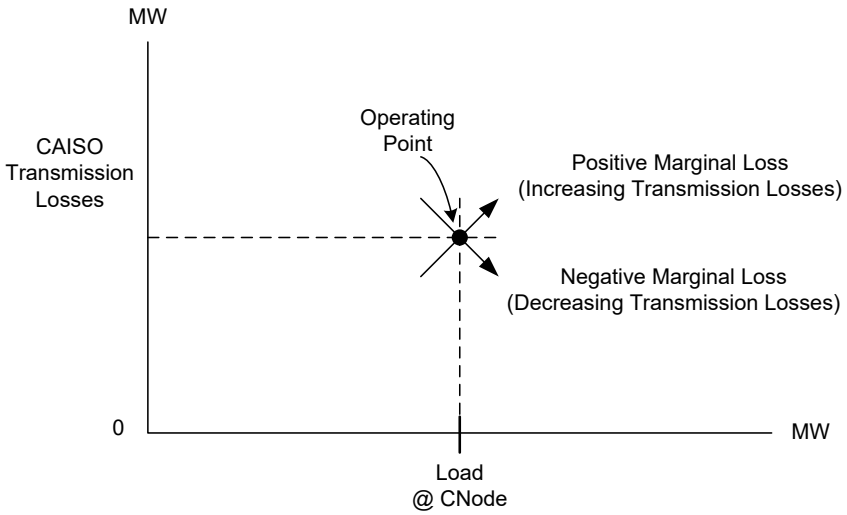
These Marginal Loss Factors are used in the calculation of LMPs and they are determined by sensitivity analysis on the AC power flow solution while maintaining Net Scheduled Interchange (NSI) as a fixed variable for each Balancing Area. The Marginal Cost of loss component is equal to the marginal loss factor multiplied by the System Marginal Cost of Energy.

Exhibit 3-7 illustrates the definition of Marginal Losses with respect to the distributed Load reference in the CAISO Balancing Authority Area. Depending on the CNode locations, the system-wide Transmission Losses may either increase or decrease (slightly) as the Load at the CNode is increased by a small amount.

Exhibit 3-7: Marginal Losses - Conceptual Model

Marginal Loss Factors are calculated using AC power flow calculations during each market





Note 1: The “upward” or “downward” direction of the curve depends on the choice of Reference Bus

Note 2: The operating point is independent of the choice of Reference Bus

solution. Thus, they are dynamic factors that change for each Trading Hour in the DAM and each 15 minute interval in the RTM.

Marginal Loss Factors are not expressly published by CAISO, but they can be calculated from the published components of LMP.

The actual MW losses are used in parts of Settlement such as UFE, but are not part of the LMP calculation – the LMP reflects the rate of change in losses, not the total MW lost.

The CAISO Energy Settlement process includes settlement of the marginal cost of losses through the Marginal Cost Component of the LMP. Because Marginal Losses are higher than actual losses (almost by a factor of 2), the LMP settlement results in loss over collection. CAISO distributes the surplus losses to Scheduling Coordinators through the allocation of the IFM Marginal Losses Surplus Credit as explained in CAISO Tariff Section 11.2.1.6, or for the Real-Time Market, through its Neutrality Adjustments in CAISO Tariff Section 11.14. More details are in the *BPM for Settlements and Billing, Section 11.4.*

CAISO excludes the Marginal Cost of Losses on branches that are within embedded and adjacent Balancing Authority Areas, Metered Subsystems which do load following, and PTO networks that are outside the CAISO Balancing Authority Area.

CAISO calculates actual MW losses in these areas to maintain consistency with the State Estimator's power flow solution, and the MW losses affect the balance of Supply and Demand. However, the actual MW losses in these areas are reported separately for Unaccounted for Energy (UFE) calculations as well as being excluded from LMP calculations.

3.1.7 Nomograms

A Nomogram is used to define a constraint relationship between two power system MW variables. Exhibit 3-8 illustrates a Nomogram where the vertical axis represents the constraint and the horizontal axis represents the independent variable. Typical Nomograms are for the following, where the first mentioned name is the constrained variable and the second mentioned name is the independent variable:

- AC interface MW flow versus AC interface MW flow
- AC interface MW flow versus area MW Generation

CAISO derived Nomograms are based on network analysis and reliability studies. CAISO maintains a library of Nomogram definitions and associated parameters, which is maintained by CAISO Regional Transmission Engineers to reflect current power system conditions. The

market applications retrieve the active Nomogram definitions and incorporate them into the market optimization constraints such that the end result is to Re-dispatch Generation to satisfy the Nomogram constraints by staying within the enclosed region.

It should be emphasized that Nomograms can be used to not only restrict the flow of Power over the transmission network, but can also be used to restrict the flow of area interchange or area Generation.

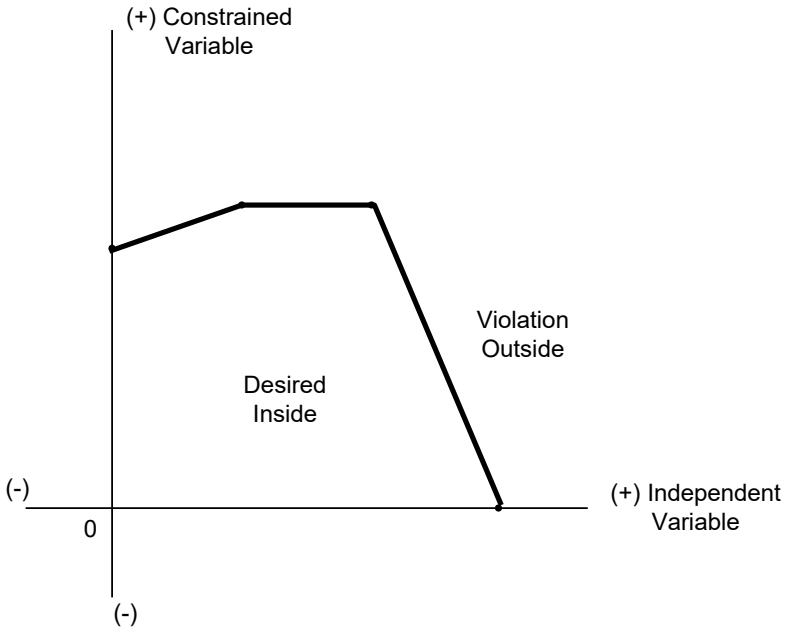
To be modeled in the market software, which uses quadratic optimization – a Nomogram must be piecewise-linear and convex. Where this is not the case, the Nomograms need to be enforced in other ways. For some cases, the Nomogram limits are based on specific contingencies, and CAISO can include the same contingencies in the market runs. Each market has the capability of modeling contingencies, and including these contingencies gives the same outcome as if CAISO had modeled them as Nomogram limits.

If Outages already exist on related network branches, then the result of the Contingency is more restrictive than the original Nomogram limit, which is the result of more reliable system operation.

Complex Nomograms are part of some operating procedures, and some of these may be more difficult to include in the market software. In these cases CAISO enforces the Nomograms through monitoring by CAISO Operators and Exceptional Dispatch in RTM.

Refer to the *BPM for Managing Full Network Model* for further details on the development and application of Nomograms together with examples.

Exhibit 3-8: Nomogram



3.1.8 Transmission Element & Transmission Interfaces

The FNM incorporates limits on individual transmission lines and transformers, as well as for composite transmission paths called Transmission Interfaces, which are defined as a constraint on flows across one or more transmission facilities.

Limits on specific transmission facilities may be flagged as follows in the market optimization process:

- Enforced
- Monitored
- Ignored

As a general rule, all transmission limits are enforced in the market optimization process such that flows on the transmission system from the optimal resource Dispatch do not violate the specific limits. However, limits on specific transmission facilities may be flagged as only "monitored" or "ignored" in cases where the limits are suspected of being invalid, or are not enforced for reasons such as being in a MSS or IBAA. The enforcement flags are specified for all transmission facilities, Transmission Interfaces, and Nomograms, and are specified for each market type.

CAISO maintains a database of all such transmission limits, and their enforcement flag is maintained by CAISO's Regional Transmission Engineers.

Furthermore, individual transmission facilities and Transmission Interface definitions contain an attribute that defines the constraint as either:

- Competitive
- Non-Competitive

These attributes are used in the Market Power Mitigation process. See Section 6.5.3, Competitive Path Criteria.

A Transmission Interface represents the composite interface of two or more network branches (e.g., lines and transformers). These groups are defined by CAISO based on power system studies and the flow of power scheduled into the markets. A Transmission Interface is commonly identified by a name, such as Palo-Verde. A Transmission Interface or group of interfaces may be nested within a larger Transmission Interface.

Transmission Interfaces are treated as constraints in the Unit Commitment and dispatching processes. In other words, the flow of power across a path is limited to avoid system reliability concerns in the power system.

Limits that are defined by CAISO operating procedures are enforced in the market software to the extent that they are piecewise-linear and convex, or that they can be replicated through Contingency analysis. Limits on path flow and scheduling rights are enforced on interties. Generally, branch flow limits are enforced on the CAISO Controlled Grid that is within the CAISO Balancing Authority Area.

Limits are also enforced on schedules which comprise the CAISO Controlled Grid outside the CAISO Balancing Authority Area that is a network facility, to ensure that schedules remain within the Converted Rights that have been turned over to CAISO's Operational Control.

Branch flow limits are monitored but not enforced in Metered Subsystems, embedded and adjacent Balancing Authority Areas, and CAISO Controlled Grid networks outside the CAISO Balancing Authority Area. Constraints are also monitored but not enforced within the CAISO Balancing Authority Area if operational experience of Real-Time conditions determines that modeled flows do not match actual flows. Constraints are ignored only if monitoring them does not provide useful information for CAISO operations.

To attain uniqueness of prices related to transmission constraints, all constraints used to model transmission elements are formulated with additional slack variables.

Transmission Interfaces and constraints are further described in the *BPM for Managing Full Network Model, Section 4.2*.

3.1.9 Scheduling Points

A Scheduling Point is a location in the Base Market Model at which Scheduling Coordinators may submit Intertie Bids in the CAISO Markets.
A Scheduling Point typically is physically located outside of the CAISO Controlled Grid (e.g., at the point of interconnection between an external Balancing Authority Area and the CAISO Controlled Grid). NPTO Scheduling Points are within the CAISO Control Grid, but still outside the CAISO Balancing Authority Area. Default IBAA Scheduling Points may be mapped for modeling and pricing purposes to other physical locations as further described in Section 27.5 of the CAISO Tariff and the BPM for the Full Network Model.

Scheduling Points are listed on the CAISO website:

http://www.caiso.com/1f94/1f94cd5447620.html

Within the CAISO Balancing Authority Area, resources must schedule at actual physical location, either at the specific resource location or using aggregations approved by CAISO.

Within New PTO networks of Converted Rights that extend outside the CAISO Balancing Authority Area, imports and exports are scheduled at Scheduling Points that are not the actual location of Generation or Load in the other Balancing Authority Areas for which CAISO typically does not know the actual location when the market runs.

3.1.10 Unscheduled Flow Estimation

Unscheduled loop flows occur because, outside of California, the Balancing Authority Areas within the Western Interconnection rely on contract path scheduling between Balancing Authorities. This assumes that electricity flows along a designated point-to-point path when in fact electricity flows are distributed throughout the AC transmission network. For example, a contract path schedule of 100 MW over Intertie T1 may actually result in 80 MW of the schedule to flow over T1 and 20 MW of unscheduled loop flow over Intertie T2. If the CAISO does not account for the 20 MW of unscheduled loop flow on T2, it may accept CAISO Market Schedules on T2 assuming this 20 MW of capacity is available, thereby creating infeasible schedules and potentially scheduling more Energy to flow over the Intertie than the physical limit. Unscheduled loop flows can result from almost any transaction in the interconnected grid.

If the CAISO were to wait until Real-Time to recognize and manage the physical limits of Interties, there would be less flexibility to commit units to offset infeasible schedules. This may lead to re-dispatch of expensive Generation or even Exceptional Dispatches to resolve the infeasibility, leading to higher costs and Real-Time Congestion Offset uplift costs. Instead, the loop flow is incorporated into DAM as well as RTM, to produce feasible schedules with prices that more accurately reflect the conditions that will be experienced in Real-Time.

In order to model unscheduled loop flows, accurately enforce physical capacity limitations of the Interties, and incorporate reliability and outage information in the forward-looking horizons of DAM and RTM, the Full Network Model includes the transmission topology used by the EMS State Estimator for most or all external Balancing Authority Areas, and representations of sources and sinks in these areas. (In cases where the EMS network model does not include dynamically transferred resources of the CAISO Markets, market-only additions supplement the EMS model as needed.) The CAISO obtains the Demand Forecast and Outage data needed for this modeling from Reliability Coordinator (Peak Reliability) databases developed to coordinate reliability planning. For forecasted Interchange between Balancing Authority Areas, the CAISO uses the services of a vendor, with expertise in tracking scheduled Interchange transactions, to analyze current and recent historical E-Tag data for the WECC region. The CAISO combines the vendor's data on historical scheduled Interchange and projected future scheduled Interchange, as a weighted average of these time series. The CAISO also has the ability to scale the resulting forecasted Interchange to ensure that this input to the market optimization matches actual Real-Time conditions as closely as possible. Combining the Demand Forecast with the forecasted Interchange for a Balancing Authority Area produces the generation forecast for that area. In RTM, the CAISO can supplement this modeling with State Estimator results to match actual telemetered Real-Time flows by calculating compensating injections at Interties or other locations in the network.

3.1.11 Nodal Group Limit Constraints

In order to ensure AC convergence under Virtual Bidding, the software is capable of enforcing nodal group MW limit constraints on a location basis to limit the volume of Bids at a particular location or set of locations. These nodal group MW limits will only be used when an AC solution is not attainable within the IFM before the Day-Ahead Market clears. When a nodal group MW limit enforcement is needed, it will be applied to the total flow affected by both physical and Virtual Bids.

The CAISO will enforce nodal group MW limit constraints to help ensure AC power flow solutions. The process for determining whether to enforce nodal group MW limit constraints is shared between the Security Constrained Unit Commitment (SCUC) module and the transmission network analysis (TNA) module processing. The TNA will identify nodal groups where MW limits should be enforced and the SCUC will include the appropriate constraints in the optimization problem formulation.

To identify the enforced nodal group MW limit constraints, it is assumed that more injection (combined physical and virtual) is being awarded at specific points in the system than the system is really capable of supporting. Therefore the objective is to identify where excess injections have been awarded at key locations in the system. To accomplish this analysis, the first task is to look for PNodes where large injection awards have been made by ordering the PNodes according to the largest injection MW quantity relative to the MW limit at that PNode (i.e. absolute total injection MW divided by PNode MW limit expressed as a percentage at each location). The second task is to identify if the large MW injections are at key locations in the system. These key locations are pre-defined in a static list and determined based on an analysis of power flow studies. The list of key locations will be updated as network conditions change.

After the enforced constraints have been identified, they will be ordered in terms of those that have the largest relative percentage violation of their MW limit and the Pnodes that exceed a pre-defined threshold. The first iteration chooses the top N PNodes (configurable) from the ordered list. The configurable number will be initially determined by analysis of market simulation results and internal structured testing prior to the implementation of convergence bidding, and may be updated based on actual operating experience. If this iteration fails to lead to AC convergence then subsequent iterations will choose larger numbers of PNodes from the ordered list.

Once the nodal group MW limit constraints are identified and being enforced, the market software will calculate the corresponding PNode MW limits according to the following rules:

1) For PNodes that have physical Supply Resources, the nodal maximum MW limit will be defined to be the MW maximum of the physical Supply Resources based on the Master File PMax. The minimum nodal MW limit is set to zero as the default value.

2) For PNodes that have Demand Resources, the nodal minimum MW limit will be defined to be the negative of the Load Distribution Factor for the PNode times the CAISO Forecast of CAISO Demand MW value. The nodal maximum MW limit is set to zero as the default value.

3) Except for Default Laps and Trading Hubs, for PNodes that have no Generator or Demand connected then Virtual Bidding is not allowed. Virtual Bids are only allowed where there are physical resources at the location associated with a PNodes.

4) The final Nodal Maximum MW Limits are the values calculated by the above rules multiplied by a configurable percentage, which is defined on a nodal basis.

5) The final Nodal Award Minimum MW Limits are the values calculated by the above rules multiplied by a configurable percentage, which is defined on a nodal basis.

6) The configurable percentages applied to the maximum and minimum MW limits will be based on an engineering analysis of power flows run with the Full Network Model. The percentages will be set to allow for the production of consistent AC solutions.

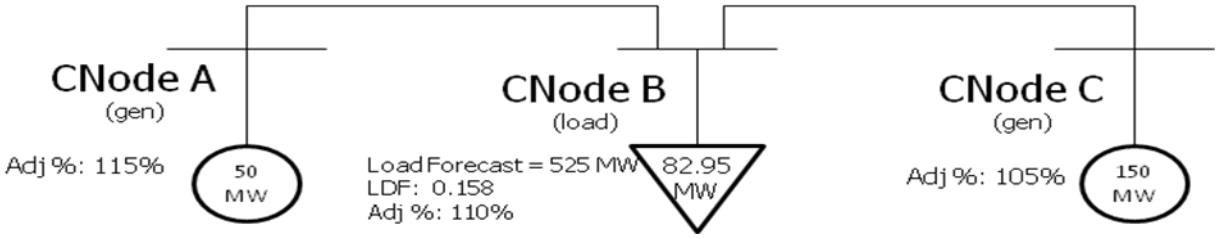
7) There are no Nodal Maximum MW limits imposed on Default LAPs or Trading Hubs directly.

If the automated iterative process described above does not result in achieving an AC solution, the ISO will identify PNodes that have physical Supply Resources that are on outage or not fully participating in the ISO market and manually set the nodal constraint as low as the zero.

For nodal group MW limit purposes, physical Supply and Virtual Supply Bids are treated as positive values. Physical Demand and Virtual Demand are treated as negative values. The Nodal Maximum MW Limit is a positive value indicating the limit of how much net physical Generation or Virtual Supply can be allowed at a PNode. The Nodal Award Minimum MW Limit is a negative value and indicates the limit of how much net physical Demand or Virtual Demand can be allowed at a PNode. Information for nodal group MW limits will be published to Market Participants in the similar way as other transmission constraints. Refer to the *BPM for Market Instruments*, Section 12.

Example

Three CNodes (A, B, and C) are connected to physical resources and have associated virtual injections.



CNode A is connected to a Generator with a maximum MW value of 50 MW. CNode B is a load node. The CAISO Forecast of CAISO Demand is 525 MW and the load distribution factor is 0.158. CNode C is connected to a different Generator with a rating of 150 MW. Configurable percentages were set to 115% and 105% for Generators at nodes A and C respectively, and 110% for the load node[19].

Model limit calculations:

CNode A: 50 MW * 115% = 57.5 MW

CNode B: -525 MW * 0.158 * 110%= -124.425 MW (minimum limit)

CNode C: 150 MW * 105% = 157.5 MW

(Minimum limits are set to zero for nodes A and C. Maximum limit is zero for node B)

3.1.12 Controllable Devices Modeling

The CAISO controlled grid includes controllable transmission devices that enable the CAISO as the balancing authority area and transmission operator to monitor and adjust the power flow on the CAISO controlled grid (An example of these devices include but not limited to ISO controlled HVDC, Phase Shifting Transformer, and any other controllable devices). Controllable transmission devices are designed to ensure the reliable and secure operation of the grid is maintained. Controllable transmission devices help control the power flow through transmission lines. The CAISO market systems optimizes the controllable transmission devices as part of its

[19] The values 115%, 105% and 110% were selected for illustration purposes only. The values are not necessarily representative of values that are used in production.

security constrained economic dispatch and security constrained unit commitment. The CAISO market systems will calculate and issue the optimal position for the controllable device to the transmission owner. Pursuant to operating procedures, the transmission owner modifies the controllable device pursuant to the CAISO market instruction.

The CAISO will not enforce the optimization of the controllable device in any of the CAISO Markets if the CAISO has determined that: (1) there are modeling inaccuracies, including inaccuracies in available data; or (2) doing so could result in adverse reliability impacts.

3.1.13 Generator Contingency and Remedial Action Scheme modeling

3.1.13.1 Overview

The security constrained economic dispatch (SCED) will account for the impacts of:

- Generation or load loss in the dispatch
- Transmission loss along with subsequent generation or load loss due to Remedial Action Scheme (RAS) operation in the dispatch.
- Transmission reconfiguration due to RAS operation in the dispatch.

The generator contingencies and remedial action scheme constraints in the day ahead market (DAM), real time market (RTM), and Western Imbalance Energy Market (EIM), when enforced, will result in the most efficient and reliable generation dispatch through the market, in the base case as well as in the contingency cases, by reserving enough transmission capacity in the right places to account for the change in flows caused by the loss of generation or load. When generation or load is lost, the system has an immediate response whereby all frequency response enabled resources on the system will automatically adjust their output to compensate for the load and supply imbalance. The loss of generation or load and the system response to the loss of generation or load creates dramatically different flows on the system in the post contingency state. If the contingency were to happen, the resulting flows would not be greater than the emergency ratings on any transmission elements in the system.

The day ahead and real time markets will:

- Allow for the benefits of increased transmission capability while protecting the transmission system with remedial action scheme events;
- Pre-dispatch generation such that transmission lines will not overload if a generator event or remedial action scheme event were to occur; and

- Price the contribution to congestion for generators on remedial action schemes versus generators not on remedial action schemes.

3.1.13.2 Treatment of virtual supply/demand

Virtual supply demand schedules in the day ahead market at the generator/load nodes where the generator/load is part of the GCARM contingency definition will be treated the same as the physical generation/load at these nodes.

If the generator/load is outaged, the virtual supply/demand schedules will vanish in the post-contingency state and they will be distributed to the online frequency-responsive generators in the entire market using the same generation/load loss distribution factors used for the physical generation/load.

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:

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

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 energy, 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 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 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 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

The CAISO Markets are based on using an FNM coupled with LMPs. As noted above, the FNM is comprised of a detailed model of the physical power system network along with an accurate model of commercial scheduling and operational arrangements, to ensure that the resulting LMPs reflect both the physical system and the schedules produced by the market applications. Section 2.3 of the *BPM for Managing Full Network Model* describes the integration of the FNM and Market Operations.

The LMP is the marginal cost (expressed in $/MWh) of serving the next increment of Demand at that PNode consistent with transmission facility constraints, transmission losses, and the performance characteristics of the resources as detailed in Section 3.1. LMPs are calculated at PNodes, which are CNodes that are Modeling Points or have other informational value. The LMP for Trading Hubs, Default Load Aggregation Point (DLAP), WEIM Load Aggregation Point (ELAP), Custom Load Aggregation Point (CLAP), Sub Default Load Aggregation Point (SLAP), Metered Sub-system Load Aggregation Point (MLAP), and Aggregate Scheduling Tie Points for a given interval is the price as produced by the market optimization run based on the distribution factors at the constituent Pricing Nodes and by the effectiveness of the Aggregate Pricing Node in relieving a Transmission Constraint within the effectiveness threshold as specified in tariff Section 27.3.4.6.LMPs for all other Aggregated Pricing Nodes (APNodes, which are groupings of PNodes used for bidding and pricing in the CAISO Markets) are calculated after Market Clearing as the weighted average of the LMPs at their individual PNodes, using distribution factors as the weighting factors. Using the FNM in the DAM and the RTM incorporates Transmission Losses into the Market Clearing, and allows modeling and enforcing all network constraints. This results in LMPs for Energy that reflect the System Marginal Energy Cost (SMEC), Marginal Cost of Losses (MCL), and Marginal Cost of Congestion (MCC). The SMEC component of the LMP is the same for all PNodes, based on the selection of a certain Reference Bus. The MCL and the MCC vary across the network due to network characteristics and power flow patterns. The MCL is the SMEC times the Marginal Loss Factor at a PNode, where the Marginal Loss Factor is the derivative (i.e., rate of change) of the actual MW losses from that location to the Reference Bus, for a marginal (small) change in Load at the specified location. The Marginal Loss Factor is determined as part of the AC power flow solution during each Trading Hour in the DAM and each 15 minute interval in RTM. The MCC is the cost of congestion between a PNode and the Reference Bus. Because of the impact of the Reference Bus on the components of LMP, the CAISO uses a distributed Reference Bus for LMP

calculation that weights the calculated components among PNodes throughout the CAISO Balancing Authority Area. Further details are in Section 3.1 and in subsections below.

3.2.1 LMP Disaggregation

In understanding the mechanics of LMP disaggregation, it is important to distinguish three separate reference variables that affect AC OPF results:

1) Angle reference: In Power flow calculations, the distribution of flows throughout the network involves calculation of phase angles, which are measured from a single reference location. There must be a single angle reference bus for the entire system (unless the system has multiple islands, in which case each island would have an angle reference bus). Although the angle reference bus is essential to Power flow calculations, CAISO's intent in specifying the Market design is that the selection of the angle reference bus does not affect the prices that result from the Market. Keeping the market results independent of the choice of angle reference bus involves the definition of the other reference variables for system Power balance and LMP disaggregation.

2) Power system slack: In an AC Power flow model, among the solution options is the use of a single bus or a distributed generation or distributed Load slack variable for system Power balance. Using a single slack bus means that adjustments to the MW output of system supply as a whole, to maintain a balance between supply and Demand, occur using Generation located at a single bus. When the results of an AC OPF Market simulation are computed and a single slack bus is used in the Power flow calculations, it is common to use the LMP at this bus as the system Energy cost, since this is where incremental adjustments to supply occur to maintain the system Power balance. Since changes in Load at the slack bus are met by changes in Generation at the same bus, marginal losses are zero at the slack bus, and marginal losses at other buses are measured relative to the slack bus; this calculation of the LMP components is valid if and only if the change in supply occurs at the same location as the change in Load.[20] In contrast, a distributed Generation slack

[20] When changes in load at the slack bus are matched by changes in Generation at the same bus, flows between other buses in the network do not change, losses in the system do not change, and marginal losses are zero. However, if the change in load at one bus are matched by changes in Generation at other buses, then flows in the network do change, which causes losses in the system as a whole to change, and marginal losses (i.e., the change in system losses per increment of change in load) are not zero.

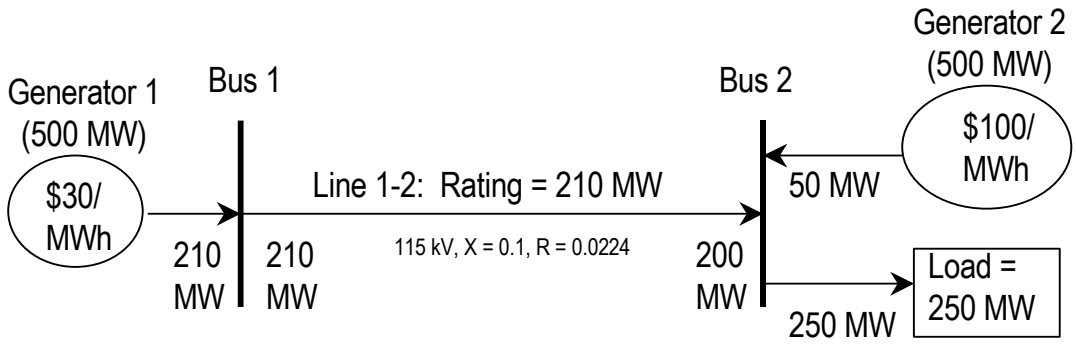
variable makes adjustments to all Generation to maintain the balance between supply and Demand, instead of adjusting a single Generator. With a distributed Load slack adjustments are made to Loads throughout the system in order to maintain Power balance. When a distributed slack variable is used (either a distributed Generation slack or a distributed Load slack), adjustments to maintain the system Power balance are independent of the choice of angle reference bus because they occur throughout the network. CAISO uses a distributed Load slack in all applications except IFM where distributed generation slack may be used.

3) LMP reference: The third reference variable involves the definition of the Energy and loss components on LMPs. The Energy component is the same at all locations in the network and is defined by the distribution of either Generation or Load, and the loss component is similarly defined as a measurement of the system's response to changes in injections or withdrawals that are distributed throughout the network. The concept of computing LMP components at a single reference bus, versus using a distributed reference that reflects adjustments that are spread throughout the network, is similar to the slack reference that is used for system Power balance. The calculations of system Power balance and LMP disaggregation can occur separately, but there is little reason (other than software configuration) to measure LMP components using a different reference than the Power balance equations. As is the case when a distributed slack variable is used for maintaining system power balance, the results of LMP disaggregation are independent of the choice of angle reference bus because the reference variable is distributed throughout the system. This meets CAISO's intent, in the Market design, that the selection of the angle reference bus does not affect the prices that result from the Market.[21]

If a single slack option is chosen, CAISO will choose a slack bus that is centrally located in the CAISO Balancing Authority Area. In case the distributed load slack option is chosen, the load slack adjustments are made to load throughout the system using system LDFs. When distributed generation slack is chosen, adjustments will be made to the generation output of generating units to maintain power balance. The selection of generating units, participating in the slack adjustments is made economically based on the amount of MW available for adjustments on the generating units.

[21] The independence of the LMP disaggregation using a distributed reference variable from the selection of angle reference bus is both a theoretical result, since the distribution of load or Generation is not affected by the choice of angle reference bus, and an empirical result that appears in the outputs of LMP software.

The distinctions among these quantities can be seen by considering a two-bus example, in which 500 MW Generators are located at each Bus 1 and Bus 2 with a $30/MWh Bid at Bus 1 and a $100/MWh Bid at Bus 2. There is a Load of 250 MW at Bus 2. The transmission line from Bus 1 to Bus 2 has impedances as shown (reactance = X = 0.1, resistance = R = 0.0224, per unit)and a rating of 210 MW at each end. Each Generator has a large reactive Generation capability, and controls its own bus voltage to 1.0 per-unit.



Generator 1 has the lowest Bid, but cannot serve all 250 MW of Load at Bus 2 due to the 210 MW limit on Line 1-2. Losses on Line 1-2 result in 200 MW reaching Bus 2, so the remaining 50 MW of Load at Bus 2 must be served by Generator 2. Additional Load at Bus 1 could be served by Generator 1 at $30/MWh, and additional Load at Bus 2 could be served at $100/MWh by Generator 2, so the total LMPs are $30 and $100/MWh at Bus 1 and Bus 2, respectively. For four alternative model formulations, the disaggregated LMP results are as follows:

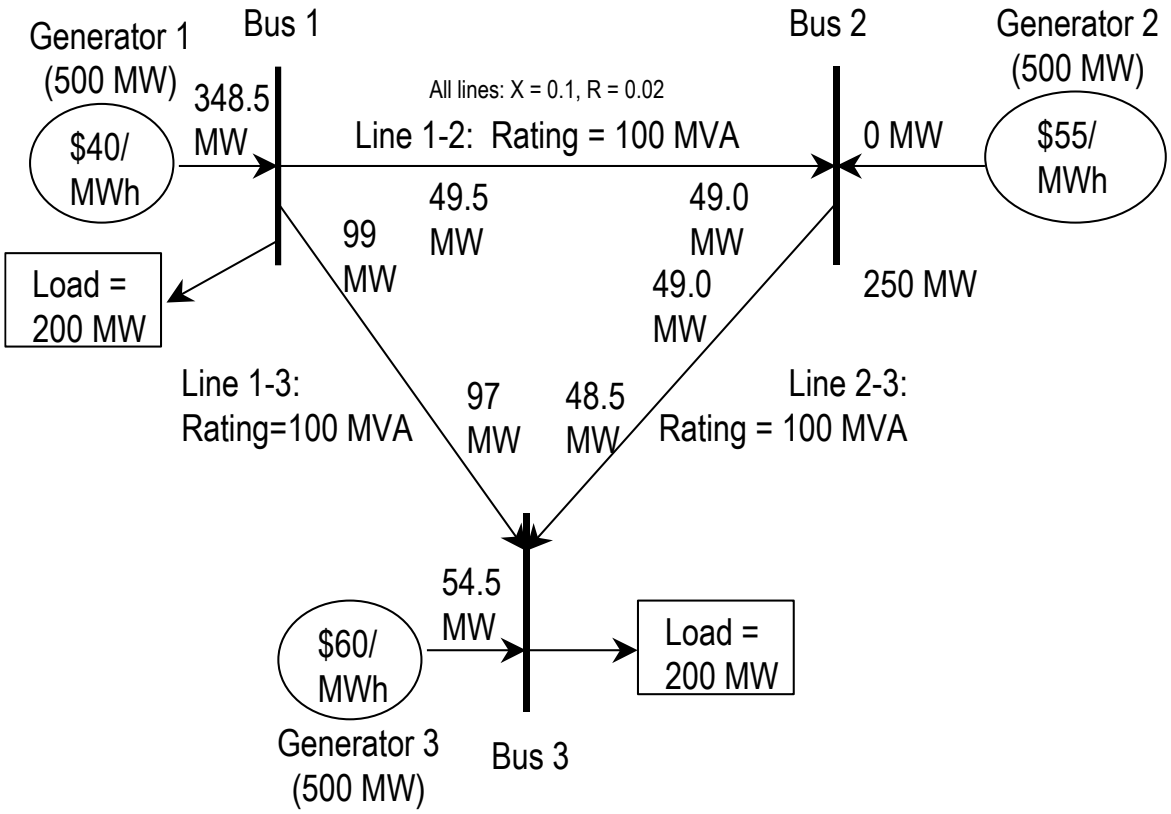
LMP Location	Total LMP	Energy	Loss	Congestion	Shadow Price
LMP Reference:	**Single Bus #1**	**Angle Ref.:**	**Bus 1**		$60.59/MW
Bus 1	**$30/MWh**	$30/MWh	$0/MWh	$0/MWh	
Bus 2	100	30	3.12	66.88	
LMP Reference:	**Single Bus #2**	**Angle Ref.:**	**Bus 2**		60.59
Bus 1	**30**	100	-9.41	-60.59	
Bus 2	100	100	0	0	
LMP Reference:	**Distributed**	**Angle Ref.:**	**Bus 1**		60.59
Bus 1	30	100	-9.41	-60.59	
Bus 2	100	100	0	0	
LMP Reference:	**Distributed**	**Angle Ref.:**	**Bus 2**		60.59
Bus 1	30	100	-9.41	-60.59	
Bus 2	**100**	**100**	**0**	**0**	

In the first model formulation, LMP components are computed using a single bus (Bus 1) as the reference for LMP disaggregation and the angle reference bus is Bus 1. Bus1's LMP defines the System Marginal Energy Cost of $30/MWh. As noted above, additional load could be served at Bus 1 for $30/MWh, with no additional losses or congestion. Since this first model uses a single reference bus at Bus 1, the difference between loss and congestion prices at the two buses is stated as non-zero prices at Bus 2. Relative to the reference bus at Bus 1, running AC power flow software to account for interactions between MW and MVAr flows produces a "loss penalty factor" at Bus 2 of 0.9059: if the flow at Bus 1 were increased by an increment of 1 MW, the incremental change in flow at Bus 2 would be 0.9059 MW, after losses in the line. (Numbers in this discussion are rounded for presentation purposes.) That is, serving an additional 1 MW of Load at Bus 2 could be served by the less expensive Generator at Bus 1, if the constraint limit at Bus 1 and the output of Generator 1 were increased by (1/0.9059) = 1.1039 MW. This represents both the Energy that arrives at Bus 2 and the Energy that is lost in the transmission network, and the Marginal Loss Factor = 1.1039 – 1 = 0.1039. The Marginal Cost of Losses at Bus 2 = Marginal Loss Factor * System Marginal Energy Cost = 0.1039 * $30/MWh = $3.12/MWh. The Marginal Cost of Congestion at Bus 2 = total LMP - System Marginal Energy Cost - Marginal Cost of Losses = 100 – 30 – 3.12 = $66.88/MWh. Because the incremental savings to the system due to the 1 MW relief of the network constraint, which is called the "shadow price" of the constraint, needs to account for the MW originating at Bus 1 vs. the MW arriving at Bus 2, the shadow price = 0.9059 * $66.88/MWh = $60.59 per MW (using a 1-hour Dispatch interval).

In the second model formulation, Bus 2 is the single reference bus for LMP disaggregation, and Bus 2 is the angle reference bus. Bus1's LMP defines the System Marginal Energy Cost of $100/MWh. Placing the Reference Bus for LMP decomposition at Bus 2, the Marginal Loss Factor is 1 – 0.9059 = 0.0941, and the Marginal Cost of Losses = 100 * 0.0941 = $9.41/MWh. The constraint limit applies at each end of the line from Bus 1 to Bus 2, and is a binding constraint at Bus 1, where the flow is higher. When the model uses a single reference bus at Bus 2, the difference between congestion prices at the two buses is stated as a non-zero price at Bus 1, and the difference in congestion prices equals the shadow price of the constraint since the constraint is limiting flows at the same location. Although the total LMPs are the same in all cases, this difference between the LMP loss components at the two buses is three times as high as in the first model formulation and has depended simply on the choice of the Reference Bus, which would thus affect Settlements that are based on LMP components. This leads CAISO uses a distributed Reference Bus that depends on the distribution of resources throughout the CAISO Balancing Authority Area, instead of on the choice of a single reference point. The shadow price of the constrained line limit is $60.59 regardless of the choice of reference bus or LMP reference formulation.

The third and fourth model formulations use the inputs as the first and second ones, but the distributed reference formulation is used for LMP disaggregation instead of the single bus formulation, where the distribution is based on Load. By using the distributed reference, the LMP disaggregation does not depend on the selection of the angle reference bus. Since the Load is only at Bus 2 in this example, the LMP disaggregation is the same as if Bus 2 were used as a single reference bus; note that the value of the LMP loss component is $0/MWh in this case. That is, using the distributed reference makes the LMP results independent of the selection of the angle reference bus. As noted above, CAISO intends to use a distributed reference for LMP disaggregation as well as using a distributed slack bus for Power balance.

The same independence of the LMP disaggregation for alternative selections of the angle reference bus can be seen for a three-bus example:



Generators 1, 2, and 3 (located at Buses 1, 2, and 3, respectively) each have 500 MW capacity, and have Bids of $40, $55, and $60/MWh, respectively. Buses 1 and 3 each have 200 MW of Load. Lines 1-2, 1-3, and 2-3 have equal impedances, and ratings of 100 MVA each. Generator

1 can serve the entire Load at Bus 1, but can only produce 148.5 MW to serve the Load at Bus 3 because of the limit on Line 1-3's capacity. (Because MVAr reactive Power flows in addition to MW Power flows, the 100 MVA capacity amounts to only 99 MW of real Power.)

For the alternative model formulations of single-bus or distributed LMP disaggregation, and selections of angle reference bus, the disaggregated LMP results are as follows:

LMP Location	Total LMP	Energy	Loss	Congestion	Shadow Price
LMP Reference:	**Single Bus #1**	**Angle Ref.:**	**Bus 1**		$26.30/MVA
Bus 1	**$40/MWh**	$40/MWh	$0/MWh	$0/MWh	
Bus 2	**49.9**	40	0.83	9.07	
Bus 3	60	40	1.67	18.33	
LMP Reference:	**Single Bus #2**	**Angle Ref.:**	**Bus 2**		26.30
Bus 1	**40**	49.9	-1.02	-8.89	
Bus 2	**49.9**	49.9	0	0	
Bus 3	60	49.9	1.03	9.07	
LMP Reference:	**Single Bus #3**	**Angle Ref.:**	**Bus 3**		26.30
Bus 1	**40**	60	-2.41	-17.59	
Bus 2	**49.9**	60	-1.21	-8.83	
Bus 3	60	60	0	0	
LMP Reference:	**Distributed**	**Angle Ref.:**	**Bus 1**		26.30
Bus 1	40	50	-1.00	-9.00	
Bus 2	49.9	50	0.02	-0.11	
Bus 3	60	50	1.04	8.96	
LMP Reference:	**Distributed**	**Angle Ref.:**	**Bus 2**		26.30
Bus 1	40	50	-1.00	-9.00	
Bus 2	49.9	50	0.02	-0.11	
Bus 3	**60**	**50**	**1.04**	**8.96**	
LMP Reference:	**Distributed**	**Angle Ref.:**	**Bus 3**		26.30
Bus 1	40	50	-1.00	-9.00	
Bus 2	49.9	50	0.02	-0.11	
Bus 3	**60**	**50**	**1.04**	**8.96**	

Similarly to the two-bus example, LMP components in the first through third model formulations are computed using a single bus as the reference for LMP disaggregation, and the angle

reference bus is varied between the three models. The difference among the LMP loss components at the three buses ranges from $1.67/MWh when Bus 1 is the reference bus to $2.41/MWh when Bus 3 is the reference bus, and the congestion component varies by offsetting amounts. (The total LMP is not affected by the selection of the reference bus, the Energy component is the same at each bus, and Total LMP = Energy + Loss + Congestion.) In the fourth through sixth model formulations, the distributed Load reference is used for LMP disaggregation, and the LMP components do not vary with the selection of the angle reference bus. Recall that the LMP loss component had the same value as if a single LMP reference bus were used at Bus 2 in the two-bus example, in which Load only exists at Bus 2, and therefore the Load-weighted average LMP loss component in that example is $0/MWh. In the three-bus example, there are equal amounts of Load at Buses 1 and 3, so the Load-weighted average LMP loss component is $0.02/MWh, which is closer to $0/MWh than to either of the LMP loss component values at these buses.

The following subsections describe each of the three cost components of LMP.

The *BPM for Managing Full Network Model, Section 4* describes the network factors that are required as part of the LMP calculation.

3.2.2 System Marginal Energy Cost

System Marginal Energy Cost (SMEC) is the component of the LMP that reflects the marginal cost of providing Energy from a CAISO-designated reference location.

CAISO uses a distributed Load reference for LMP decomposition, instead of a single slack reference bus. A distributed Load reference approach calculates the LMP components based on where the Demand actually is, using Load Distribution Factors that are updated on an ongoing basis. The use of a distributed slack for power flow calculation is discussed in the *BPM for Managing Full Network Model, Section 3.3*.

Individual LMPs for a given time period each have the same SMEC component of LMP. It is important to emphasize that the LMP value itself is not affected by how SMEC is derived.

3.2.3 Marginal Cost of Losses

Marginal Cost of Losses (MCL) is the component of LMP at a PNode that accounts for the real power Marginal Losses, as measured between that CNode and the distributed Load reference. The MCL is calculated as the product of SMEC and the Marginal Loss Factor at that PNode. The MCL at a particular PNode may be positive or negative, depending on the submitted Bids. The Marginal Loss Factors are derived by the market optimization software (IFM/RTM).

All scheduled Energy Transactions (including Demand, Supply, and Inter-SC Trades) are settled using the loss component of the LMP at the location of the transaction. For example, when a Supply is paid for the Energy that it delivers, and the loss component of its LMP is negative, it is charged (negative payment) for losses. Further information on payment for losses is included in the *BPM for Settlements and Billing*.

3.2.4 Marginal Cost of Congestion

Marginal Cost of Congestion (MCC) is the component of LMP at a PNode that accounts for the cost of Congestion, as measured between that CNode and a Reference Bus. Section 2.3.2.3 of this BPM and Attachment A of the *BPM for Managing Full Network Model* describe the use of the Reference Bus. The MCC is calculated based on a linear combination of the Shadow Prices of all binding constraints in the network, each multiplied by the corresponding Power Transfer Distribution Factor within the minimum effectiveness threshold. Shadow Prices in IFM include impacts from Virtual Awards (Supply and Demand) on binding constraints, including nodal group MW limit constraints. The MCC at a particular PNode may be positive or negative. PTDFs are calculated using sensitivity analysis on the AC power flow solution for each Trading Hour in the DAM and each 15 minute interval in the RTM. To ensure uniqueness of prices when there are binding constraints in the network, the market clearing process would create a shadow price for the Transmission Constraint, only when the relaxation of the constraint would result in a reduction in the total cost to operate the system.

3.2.1 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 BAA-level marginal capacity cost for the reliability product, a marginal cost of losses, and a marginal cost of congestion.

The three components are defined as:

1. BAA Marginal Reliability Capacity Cost: This is the capacity component of the RCMP and reflects the marginal cost of procuring the last MW of RCU or RCD from a BAA-specific perspective. It is derived from the shadow price of the BAA's individual RUC power balance constraint and is the same for all PNodes within that BAA.

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.

3.2.2 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 BAA-specific marginal capacity 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. BAA Marginal Imbalance Reserve Capacity Cost: This is the capacity component of the IRMP. It is derived from the shadow price of the BAA-specific IRU or IRD procurement constraint, which reflects the marginal bid price for the respective product. This component is the same for all PNodes within that BAA.

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

3.2.3 Flexible Ramp Up/Down Marginal Pricing

The ISO shall calculate the Locational Marginal Price (LMP) at each Location (PNode and APNode) of each BAA in the EIM Area in each interval of the market horizon as the sum of the shadow price of the Power Balance Constraint (PBC) for that BAA and interval and the Marginal Greenhouse Gas (GHG) Price for that Location and interval, divided by the Loss Penalty Factor (LPF) for that Location and interval, minus the congestion contributions from all binding constraints in the base and Flexible Ramp Up/Down (FRU/FRD) deployment scenarios; the latter are the product of the shadow price of the respective binding constraint times the shift factor of the respective Location to that binding constraint in the relevant interval.

The ISO shall calculate the Locational FRU Marginal Price (FRUMP) at each Location of each BAA that has failed the FRU sufficiency test or upward capacity test in each interval of the

market horizon as the shadow price of the FRU procurement constraint for that BAA and interval, minus the congestion contributions from all binding constraints in the FRU deployment scenarios; the latter are the product of the shadow price of the respective binding constraint times the shift factor of the respective Location to that binding constraint in the relevant interval. The ISO shall calculate the Locational FRU Marginal Price (FRUMP) at each Location of each BAA that has passed the FRU sufficiency test and upward capacity test in each interval of the market horizon as the shadow price of the net transfer constraint in the FRU deployment scenario for that BAA and interval, plus the shadow price of the FRU procurement constraint for the group of BAAs that have passed the FRU sufficiency test in that interval, minus the congestion contributions from all binding constraints in the FRU deployment scenarios; the latter are the product of the shadow price of the respective binding constraint times the shift factor of the respective Location to that binding constraint in the relevant interval.

The ISO shall calculate the Locational FRD Marginal Price (FRDMP) at each Location of each BAA that has failed the FRD sufficiency test or downward capacity test in each interval of the market horizon as the shadow price of the FRD procurement constraint for that BAA and interval, plus the congestion contributions from all binding constraints in the FRD deployment scenarios; the latter are the product of the shadow price of the respective binding constraint times the shift factor of the respective Location to that binding constraint in the relevant interval. The ISO shall calculate the Locational FRD Marginal Price (FRDMP) at each Location of each BAA that has passed the FRD sufficiency test and downward capacity test in each interval of the market horizon as the shadow price of the net transfer constraint in the FRD deployment scenario for that BAA and interval, plus the shadow price of the FRD procurement constraint for the group of BAAs that have passed the FRD sufficiency test in that interval, plus the congestion contributions from all binding constraints in the FRD deployment scenarios; the latter are the product of the shadow price of the respective binding constraint times the shift factor of the respective Location to that binding constraint in the relevant interval.

The ISO shall calculate the Scheduling Point-Intertie (SP-Tie) Locational Marginal Price (SP-Tie LMP) at each SP-Tie Location of each BAA in the EIM Area in each interval of the market horizon as the sum of the shadow price of the Power Balance Constraint (PBC) for that BAA and interval and the Marginal Greenhouse Gas (GHG) Price for that Location and interval, divided by the Loss Penalty Factor (LPF) for that Location and interval, plus the shadow prices of all binding Intertie Scheduling Limits (ISLs) and Inter-Tie Constraints (ITCs) associated with that SP-Tie Location, minus the congestion contributions from all binding constraints in the base and FRU/FRD deployment scenarios; the latter are the product of the shadow price of the respective binding constraint times the shift factor of the respective Location to that binding constraint in the relevant interval.

The ISO shall calculate the Locational FRU Marginal Price (FRUMP) at each SP-Tie Location of each BAA in the EIM Area in each interval of the market horizon as if the SP-Tie Location is a Location in that BAA, plus the shadow prices of all binding Intertie Scheduling Limits (ISLs) and Inter-Tie Constraints (ITCs) associated with that SP-Tie Location. The system shall calculate the

Locational FRD Marginal Price (FRDMP) at each SP-Tie Location of each BAA in the EIM Area in each interval of the market horizon as if the SP-Tie Location is a Location in that BAA, plus the shadow prices of all binding Intertie Scheduling Limits (ISLs) and Inter-Tie Constraints (ITCs) associated with that SP-Tie Location. This is required for the settlement of FRU awards from TGs.

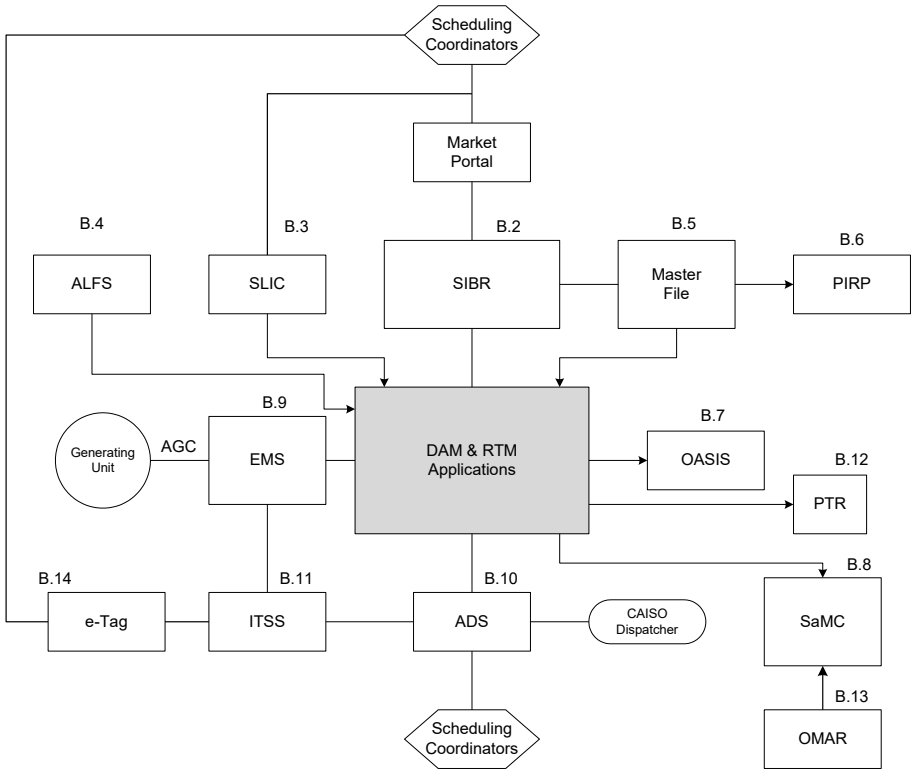
The ISO shall broadcast resource specific Locational FRU/FRD Marginal Prices for Pnode/Apnode/SP-Tie Locations and shadow prices of binding transmission and transfer constraints in the FRU/FRD deployment scenarios.

The ISO shall broadcast the FRU and FRD group capacity requirement and shadow price for the pass group and the individual BA requirement

3.3 Market Interfaces

Exhibit 3-9 presents an overview block diagram with a description of the principle supporting computer system activities as presented in Attachment B, Market Interfaces.

Exhibit 3-9: Market Interfaces



ALFS = Automated Demand Forecasting System
SIBR = Scheduling Infrastructure & Business Rules
SLIC = Scheduling & Logging of Outages
PIRP = Participating Intermittent Resource Program
OASIS = Open Access Same Time Information System
SaMC = Settlements & Market Clearing System
EMS = Energy Management System
ADS = Automated Dispatch System
ITSS = Interchange Transaction Scheduling System
PTR = Post Transaction Repository
OMAR = Operational Meter Analysis & Reporting
e-Tag = Electronic Tagging System

4. Ancillary Services

Welcome to the *Ancillary Services* (AS) section of the CAISO *BPM for Market Operations*. In this section, you will find the following information:

- A description of each of the AS Regions
- How CAISO determines AS requirements
- How CAISO procures AS
- How CAISO calculates AS Marginal Prices
- Other AS considerations
- Certification and testing requirements

4.1 Ancillary Services Regions

AS Regions are network partitions that are used to explicitly impose regional constraints in the procurement of AS, where the AS Region is defined as a set of PNodes. Regional AS procurement from resources associated with the CNodes defining the region is constrained by a lower and upper requirement. The upper requirement may be defined for each AS and also for upward AS.

AS regional constraints reflect transmission limitations between AS Regions that restrict the use of AS procured in one AS Region to cover for i) Outages in another AS Region and ii) constraints between the regions. AS regional constraints secure a minimum AS procurement (to ensure reliability) and/or a maximum AS procurement target (that increases the probability of deliverability of AS to each Region), such that the total AS procurement among Regulation Up, Spinning Reserve, and Non-Spinning Reserve reflects the current system topology and deliverability needs. Ancillary Service Regions and Sub regions are defined in the CAISO Tariff in Section 8.3.3. The CAISO may only establish New Ancillary Service Regions and Sub regions after first conducting a stakeholder process, and then only through the filing of a tariff amendment with the FERC (See Section 4.1.2, [Ancillary Services Region Changes Process], below, for more information).

4.1.1 Ancillary Services Region Definition

There are always at least two AS Regions with non-zero minimum procurement limits applied:

- **Expanded System Region** – The Expanded System Region is defined as the entire CAISO Balancing Authority Area plus all System Resources at Scheduling Points at an outside boundary of the CAISO Balancing Authority Area. Total CAISO AS procurement requirements for each of the four types of AS that are further described in the *BPM for Market Instruments* (Regulation Up, Regulation Down, Spinning Reserve and Non-

Spinning Reserve). Procurement requirements for Regulation Up and Regulation Down Mileage are enforced at the Expanded System Region only. There are no Regulation Mileage procurement requirements at the sub-regional level.

- **System Region** – The System Region is defined as the sub-set of certified resources defined in the Expanded System Region that are located internal to the CAISO Balancing Authority Area. The minimum AS regional constraints for the AS System Region are only a percentage of the AS requirements for the Expanded System Region, currently at 50%, to limit the AS procurement from System Resources for reliability purposes. The purpose of this limitation is to guard against the consequences of losing interconnection tie facilities, which would limit the AS procurement, i.e., AS delivered over a tie cannot protect the tie itself.

Besides the Expanded System Region and the System Region, eight other AS Regions are defined to ensure appropriate distribution of the AS procured for the CAISO Balancing Authority Area. These AS Sub-Regions are defined to account for expected Congestion on the Transmission Interfaces (internal to the CAISO Balancing Authority Area), as well as other system conditions, that may impact the ability of the CAISO to convert AS reserves to Energy without exacerbating Congestion on the paths that are internal to the CAISO Balancing Authority Area.

The primary purpose of the eight sub-AS Regions is to account for expected Congestion on Path 15 and Path 26. For each given hour of AS procurement, one of the following conditions is assumed:

1) No congestion forecasted on either of these two Transmission Interfaces.

2) Forecasted congestion on Path 26 in the north to south direction, which requires a minimum procurement limit on the set of resources that are south of Path 26.

3) Forecasted congestion on Path 15 in the north to south direction, which requires a minimum procurement limit on the set of resources that are south of Path 15.

4) Forecasted congestion on Path 15 in the south to north direction, which requires a minimum procurement limit on the set of resources that are north of Path 15.

5) Forecasted congestion on Path 26 in the south to north direction, which requires a minimum procurement limit on the set of resources that are north of Path 26.

6) Forecasted congestion on Path 15 in the north to south direction simultaneous with south to north Congestion on Path 26. While this scenario is expected to be

rare, it can be addressed by setting maximum procurement limits on each of the south of Path 26 AS sub-Region and the north of Path 15 AS sub-Region.

7) Forecasted congestion on Path 15 in the south to north direction simultaneous with north to south Congestion on Path 26. While this scenario is expected to be rare, it can be addressed by setting minimum procurement limits on each of the south of Path 26 AS Sub-Region and the north of Path 15 AS sub-Region.

For each of these conditions where congestion is assumed (Items 2 through 7 above), the AS Sub-Region may include the System Resources that are interconnected to that portion of the CAISO Controlled Grid. The determination of whether or not to include the System Resources in the AS Sub-Region depends on the nature of the system conditions, including the expected loading on the Transmission Interfaces that interconnect System Resources to the CAISO Controlled Grid

Based on these criteria, there are eight AS Sub-Regions in addition to the Expanded System Region and the System Region, as follows:

Exhibit 4-1: Summary of Initial AS Regions

	AS Region Name	Description of AS Region (set of resources included in AS Region)		AS Region Status
		Internal CAISO Balancing Authority Area	Intertie Resources (current Scheduling Points)	
1	*Expanded System*	All internal Generators	All	Active
2	*System*	All internal Generators	None	Active
3	*South of Path 15*	All Generators residing South of Path 15	None	Active
4	*Expanded South of Path 15*	All Generators residing South of Path 15	NW3, SR3, NV3, NV4, AZ2, AZ3, AZ5, LC1, LC2, LC3, MX, LA1, LA2, LA3, LA4, LA7	Active
5	*South of Path 26*	All Generators residing South of Path 26	None	Active
6	*Expanded South of Path 26*	All Generators residing South of Path 26	NW3, SR3, NV3, NV4, AZ2, AZ3, AZ5, LC1, LC2, LC3, MX, LA1, LA2, LA3, LA4, LA7	Active
7	*North of Path 15*	All Generators residing North of Path 15	None	Active

	AS Region Name	Description of AS Region (set of resources included in AS Region)		AS Region Status
		Internal CAISO Balancing Authority Area	Intertie Resources (current Scheduling Points)	
8	*Expanded North of Path 15*	All Generators residing North of Path 15	NW1, NW2, SR5, SR2, SMUD, TID, Sutter	Active
9	*North of Path 26*	All Generators residing North of Path 26	None	Active
10	*Expanded North of Path 26*	All Generators residing North of Path 26	NW1, NW2, SR5, SR2, SMUD, TID, Sutter	Active

All AS Regions shown in Exhibit 4-1 are "active". However, this does not necessarily mean that a minimum (or maximum) procurement limit is enforced for each of these AS Sub-Regions for a given hour. The term "active" here indicates that the AS Sub-Region is defined in the CAISO Tariff, and is included in the daily determination of applicable Regional AS limits. However, an AS Sub-Region may be "active" but also have a zero MW minimum procurement limit and a 9,999 MW maximum procurement limit, which effectively renders the AS Sub-Region as unconstrained.

AS requirements, procurement, and pricing are expressed by AS Region. The minimum and/or maximum procurement constraints are each determined individually and serve as separate constraints on the procurement of resources. A purchase of AS capacity in a specific Location on the grid may contribute to meet the requirements of several AS Regions simultaneously.

As conditions evolve, the CAISO may need to establish additional AS Regions to manage AS procurement limits for sub-AS Regions. These conditions may include:

- A pocket of Generation or Load for which more localized limits are needed to ensure sufficient capacity procurement under certain system conditions
- A System Resource at a Scheduling Point from which CAISO foresees a need to limit the AS procurement, under certain system conditions

CAISO follows the AS Region change process described in the next section, as power system conditions warrant.

4.1.2 Ancillary Services Region Change Process

The CAISO will look at a number of technical factors in determining whether to consider adjusting the boundaries of the existing Ancillary Service Regions or creating a new Ancillary Service Region. These factors include, but are not limited to, operational reliability needs, the pattern of Load growth in the CAISO Balancing Authority Area, the addition of new generating resources, the retirement of existing generating resources, the addition of new transmission facilities, changes in regional transmission limitations, changes in Available Transfer Capacity, and extended transmission or generating resource outages.

In addition, as part of a CAISO consideration of a proposed AS region change, the CAISO will conduct a market impact analysis to determine whether the changes being considered create market power issues.

The CAISO will submit its analysis and proposed action to a stakeholder process, in which stakeholders will be able to comment on any new market mitigation measures proposed in the AS region change proposal.

Finally, after consideration of stakeholder comments, the CAISO will state any intended changes to the proposed AS region change, or issue a revised analysis and then submit its proposed AS region change to the FERC as part of a Tariff Amendment filing.

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

This section is based on CAISO Tariff Section 8.6.2.

As stated in the Overview, Generating Units and Participating Loads and PDRs/PDR-LSRs (Curtailment only) certified for AS may submit Submissions to Self-Provide an AS in the IFM. Self-Provided AS effectively reduces the aggregate AS requirements that must be met from AS Bids within the same AS Region, and reduces the AS Obligation for the SC Self-Providing the AS, in the AS cost allocation. For submissions to self-provide Regulation Up or Regulation Down, the price for the capacity reservation shall be $0/MWh and the price for Mileage shall be $0.

The CAISO performs a two-step process to qualify Submissions to Self-Provide AS (referred to as “SPAS”):

4.2.1.1 AS Self-Provision Qualification

Before the market optimization is performed, the CAISO qualifies all Submissions to Self-Provide AS with respect to (i) resource certification to provide the requested Self-Provided AS, (ii) feasibility with respect to the Resource capacity limits, (iii) feasibility with respect to the relevant Resource ramp rate limits, and (iv) total self provision from all Resources with respect to any maximum Regional procurement Limit. These AS Self-Provision qualifications are performed separately for each AS type.

For item (iv) above, If the total Submissions to Self-Provide an AS exceeds the maximum System Region and regional requirement for the relevant AS in an AS Region, then Self-Provided AS is pre-qualified pro-rata with respect to their Submissions to Self-Provide AS. When there are over-lapping AS Regions defined, CAISO enforces a priority order on the AS Regions for the pro-rata qualification processing. Finally, after all regional requirements are enforced for determination of pre-qualified Self-Provided of AS, the System requirements are enforced to ensure that the total qualified Self-Provided AS does not exceed the System Region AS requirements.

- This priority order only applies to the qualification of Self-Provided AS in an AS Region where a maximum AS procurement limit is specified. Unlike minimum AS Region procurement limits, which are specified for each AS type individually, a maximum

procurement limit is enforced on all upward AS types in the AS Region collectively not to exceed the System Region AS requirements.

- Therefore, when the maximum procurement limit is reached within an AS Region due to over-supply of self-provision of upward AS, these self-provision schedules are disqualified on a pro-rata bases starting with the lowest priority AS types. The priority of upward AS types (meaning the hierarchy of valuing upward AS types), from highest to lowest, is as follows:
  - Regulation Up (highest priority)
  - Spinning Reserve
  - Non-Spinning Reserve (lowest priority)

4.2.1.2 Final Qualification Process

After the AS Self-Provision qualification process is complete, a second phase of Self-Provided Ancillary Services (SPAS) qualification takes place internal to the market optimization (in Day-Ahead or Real Time). The purpose of this second phase of qualification is to determine if any of the capacity for initially qualified SPAS (from the AS Self-Provision qualification process) is needed for Energy. If the market optimization determines that capacity submitted as SPAS is needed as Energy to resolve transmission constraints and/or satisfy the energy balance constraint (i.e., solve problem locally before looking at larger LAP Load reductions), then such Self-Provided AS capacity is partially or entirely disqualified and converted to Energy. In DAM, this conversion is possible when an Energy Bid has been submitted. In RTM, an Energy Bid is required for SPAS. Consistent with the requirements in Section 8.6.2 of the CAISO Tariff, Submissions to Self-Provide Ancillary Services are conditional to the CAISO finding that the capacity is not needed for Energy. In the event that a portion of Submission to Self-Provide Ancillary Services is not qualified, that portion of Self Provided AS will not count towards the SC's Ancillary Services Obligation (See Section 11.10.3.2 of the CAISO Tariff).

Key in this determination is identifying all Resources that are subject to the second phase of the qualification. For this purpose, a special designation flag is maintained in the CAISO Master File and sent to market applications to indicate whether a resource is subject to the optimized qualification of SPAS. This flag shall be set to "YES" for all resources with an offer obligation pursuant to a contractual or tariff obligation.

Based on the SPAS Optimization Flag, and the results of the AS Self-Provision qualification process, all SPAS capacity is labeled as one of the following for consideration in the final qualification process:

- For SPAS Optimization Flag "NO" resources, SPAS capacity qualified in the AS Self-Provision qualification process is considered unconditionally qualified, or simply *qualified*.
- For SPAS Optimization Flag "YES" resources, SPAS capacity qualified in the As Self-Provision qualification process is considered *conditionally qualified*
- Regardless of the SPAS Optimization Flag, SPAS capacity that is unqualified in the AS Self-Provision qualification process is considered *conditionally unqualified*

4.2.1.2.1 Qualified SPAS

All SPAS capacity classified as *qualified* for the final SPAS qualification process undergoes no further qualification processing and this capacity is not converted to Energy in the market optimization

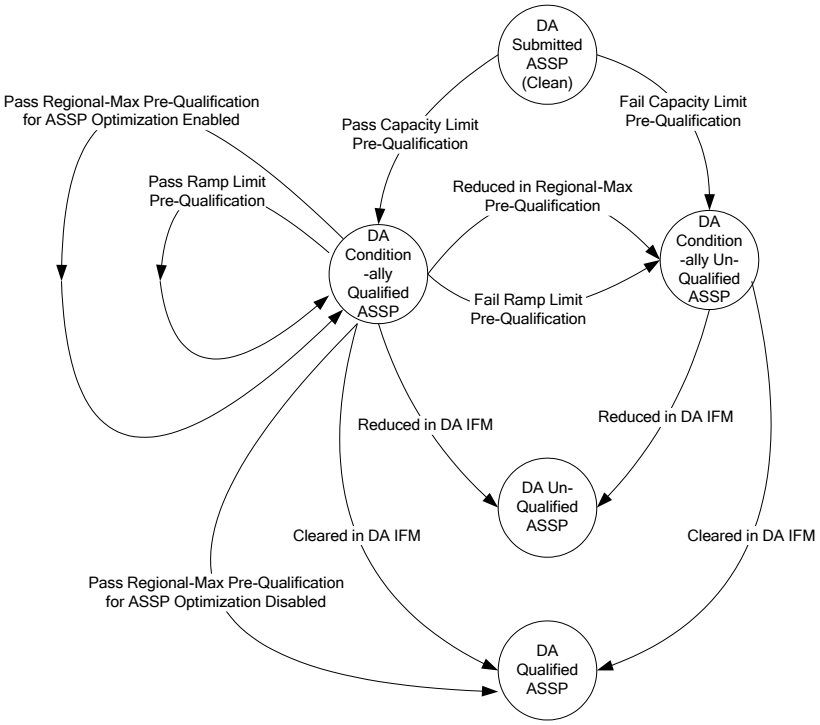
4.2.1.2.2 Conditionally Qualified SPAS

All SPAS capacity classified as *conditionally qualified* for the final SPAS qualification process may be converted to Energy to resolve transmission constraints and/or satisfy the Energy balance constraint. Such capacity is not converted to Energy unless all Economic Energy Bids are exhausted to meet these constraints, but is converted before other Self-Schedules are adjusted.

4.2.1.2.3 Conditionally Unqualified SPAS

All SPAS capacity classified as *conditionally unqualified* for the final SPAS qualification process may be converted to *qualified* SPAS. If SPAS was unqualified in the AS Self-Provision qualification process due to excess SPAS from all resources in a given AS Region, capacity classified as *conditionally qualified* on a resource that is converted to Energy in the final qualification process creates an opportunity for conditionally unqualified SPAS from other Resources in that same AS Region to qualify.

Exhibit 4-2: Qualification Process of Submissions to Self-Provide an AS



4.2.2 Conversion of Conditionally Qualified SPAS to Energy

This section is based on Section 8.6.2 of the CAISO Tariff. For the purpose of optimally converting *conditionally qualified* SPAS to Energy, a multi-segment Bid Curve is generated for each resource for consideration in the AS procurement optimization.

The most simplistic case is where a resource only provides Economic AS Bids, with no SPAS. In this case, the AS Bid is not modified for conversion of AS to Energy.

In the case where capacity from an SPAS Optimization flag "NO" Resource is *qualified* in the AS Self-Provision qualification process, then this capacity is not represented by any AS Bid segment, and therefore cannot be converted to Energy.

In the case where a SPAS Optimization flag "YES" Resource is *conditionally qualified* in the AS Self-Provision qualification process, then this capacity is assigned a penalty price P1 Bid segment, which is an artificially set at a negative price, P1, such that this capacity is cleared as AS in the market optimization before any other positive priced Economic Bids are cleared. This enables the optimization software to effectively apply a priority to the *conditionally qualified*

SPAS over economically priced AS, but also allows the optimization to recognize this capacity as less economical compared to the penalty price associated with binding transmission constraints or satisfying the Energy balance constraint. That is, if a transmission constraint becomes binding, the optimization attempts to dispatch Energy from all effective resources with Economic Energy Bids optimally to resolve the constraint. If all such Economic Bids are exhausted and the constraint still exists, then the optimization naturally finds the most optimal solution is to not clear the minimal portion of the *conditionally qualified* SPAS so that just enough Energy can be dispatched on that resource to relieve the constraint. This process effectively optimally determines exactly how much of the *conditionally qualified* SPAS can ultimately be *qualified.*

4.2.3 Conversion of Conditionally Unqualified SPAS to Qualified SPAS

This section is based on Section 8.6.2 of the CAISO Tariff. In the same process of optimally converting *conditionally qualified* SPAS to energy, a second penalty priced AS Bid Curve segment is inserted to represent the amount of unqualified SPAS determined in the AS Self-Provision qualification process, regardless of the SPAS Optimization flag indication. This penalty price Bid segment is administratively set to a smaller penalty price than for the *conditionally qualified* SPAS described above.

The purpose of classifying unqualified SPAS from the AS Self-Provision qualification process as *conditionally unqualified* is to allow this unqualified SPAS to be "re-qualified" if (i) it was originally unqualified because of a surplus of total SPAS for a given AS Region, and (ii) *conditionally qualified* SPAS on Resources in that AS Region was converted to Energy in the final qualification process.

Because the penalty price Bid segment for *conditionally unqualified* SPAS is priced higher than the *conditionally qualified* SPAS for all resources (a smaller negative penalty price), it is cleared as qualified SPAS after all conditionally qualified SPAS Bid segments are cleared, and before Economic AS bids are cleared.

This process effectively maximizes the qualification of SPAS, accounting for the optimal conversion of SPAS to Energy as necessary on such obligated resources

4.2.4 Other Details of SPAS

- The classification of SPAS resulting from the AS Self-Provision qualification process is transparent to the SC of affected Resources. Final qualification of all SPAS is reported in the publishing of IFM results, which are the end-state of the multi-step qualification process. No information is published regarding the *conditionally qualified* or

conditionally unqualified capacities, or the *conditionally qualified* SPAS that may have been converted to Energy in the final qualification process

- Self-Provided resources designated as Contingency Only are only called in the event of a Contingency, where the Contingency Flag is for the whole day. The Contingency Only designation is only applicable to real-time dispatch and does not affect the co-optimization of Energy, Ancillary Services, and Imbalance Reserve Reserves in the Day-Ahead IFM.
- Self-provision of AS is not allowed from System Resources, since the cost of transmission Congestion must be considered in the Energy and AS co-optimization. System Resources can bid down to the "AS Bid floor" ($0/MWh) to ensure that they are scheduled as Price Takers.
- Resources may Self-Provide AS and bid in the AS market for the same service for the same hour in the same market.

4.2.5 Ancillary Service Award Allocation on Energy Bids

The market optimization applications requires an Energy Bid to be able to Dispatch any Operating Reserve awards in the RTM, irrespective of whether these awards are from qualified self-provision or accepted AS Bids, and whether they are awarded in the IFM or RTM. To effectively reserve contingent Operating Reserve from Dispatch, the RTM applications need to determine the portion of the Energy Bid that corresponds to that service so that its price is replaced with the appropriate penalty price.

Furthermore, the AS allocation on the Energy Bid is required for ex post Instructed Imbalance Energy calculation, which is by service and Energy Bid segment. This information is used in the Bid Cost Recovery and No Pay mechanisms.

Each RTM application retrieves updated Outage information from outage management system at each Dispatch time and then allocates each Ancillary Service Award onto the Energy Bid as follows:

- If the resource provides Regulation Up, the capacity portion equal to the Regulation Up AS Award just below the upper regulating limit or the upper operating limit (considering derates), whichever is lower, is reserved for Regulation Up. In the event of a derate, the awarded Regulation Up Capacity is shifted down. If as a result, the Regulation Up AS Award overlaps with the Energy Bid, the overlapping portion of the Energy Bid is ignored. If the Regulation Up AS Award extends below the Day-Ahead Schedule (due to a derate), the Regulation Up AS Award is clipped from below to the Day-Ahead Schedule and the entire portion of the Energy Bid above the Day-Ahead Schedule is ignored.

- If the resource provides Regulation Down, the capacity portion equal to the Regulation Down AS Award just above the lower regulating limit or the lower operating limit (considering overrates), whichever is higher, is reserved for Regulation Down. If the Regulation Down AS Award overlaps with the Energy Bid, the overlapping portion of the Energy Bid is ignored. If the Regulation Down AS Award extends above the Day-Ahead Schedule (due to an overrate), the Regulation Down AS Award is clipped from above to the Day-Ahead Schedule and the entire portion of the Energy Bid below the Day-Ahead Schedule is ignored.

- If the resource provides Spinning Reserve, the Energy Bid portion equal to the Spinning Reserve AS Award below the allocated portion for Regulation Up, if any, otherwise below the upper operating limit (considering derates), or the top of the Energy Bid, whichever lower, is reserved for Spinning Reserve. If the total Spinning Reserve AS Award extends below the Day-Ahead Schedule (due to a derate), the total Spinning Reserve AS Award is clipped from below to the Day-Ahead Schedule.

- If the resource provides Non-Spinning Reserve, the Energy Bid portion equal to the Non-Spinning Reserve AS Award below the allocated portion for Regulation Up and Spinning Reserve, if any, otherwise below the upper operating limit (considering derates), or the top of the Energy Bid, whichever is lower, is reserved for Non-Spinning Reserve. If the total Non-Spinning Reserve AS Award extends below the Day-Ahead Schedule (due to a derate), the total Non-Spinning Reserve AS Award is clipped from below to the Day-Ahead Schedule.

- The remaining portion of the Energy Bid, if any, is used for Dispatch and additional AS procurement as applicable.

A Market Participant is allowed (subject to SIBR validation) to submit and designate either "Contingency Only" or "not-Contingency Only" for Spinning and Non-Spinning Reserves, for all 24 hours, according to the following rules:

- If Spinning Reserve is designated as Contingency Only, then Non-Spinning Reserve must also be designated as Contingency Only.

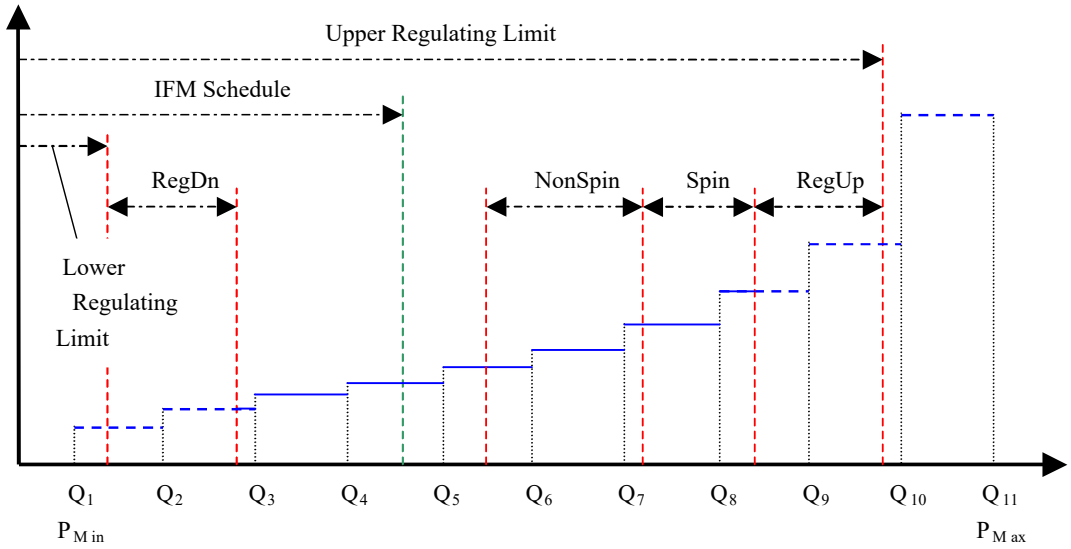
- If Spinning Reserve is designated as not-Contingency Only, then Non-Spinning Reserve must also be designated as not-Contingency Only.

- There cannot be a portion of the same service designated as Contingency Only and another portion of the same service designated as not-Contingency Only.

- The Contingency Flag is set for both types of AS, not for an individual service.

Exhibit 4-3 illustrates the AS Award allocation on an Energy Bid that spans the entire dispatchable capacity of a resource. Any portions of the Energy Bid for capacity allocated to Regulation Up and Regulation Down or beyond that (dashed lines in Exhibit 4-3) are ignored.

Exhibit 4-3: Ancillary Service Award Allocation on the Energy Bid



Energy Bids are required to dispatch Operating Reserve, but they are not needed for Regulation. A Regulation Up AS Award is allocated under the applicable upper regulating limit or the derated upper operating limit if lower, irrespective of whether there is an Energy Bid or not for that capacity range. Any overlapping Energy Bid portion is not used for dispatch.

The upper portion of the resource capacity from its Upper Regulating Limit is allocated to Regulation regardless of its Energy Bid Curve. This is done if the resource is awarded Regulation in the DAM or it has bid into RTM Regulation market. Regulation is not Dispatched based on its Energy Bid Curve price. Rather, Regulation is Dispatched by AGC based wholly on the resource's effectiveness to re-establish the system frequency target, and taking into consideration the resource's operating constraints, such as Ramp Rate. Also note that, AGC dispatches resources based on prices that are internally created by EMS system to coordinate control across all resources on AGC control. This coordination is necessary to ensure that AGC does not concentrate only on a few resources. This is for control not for pricing purposes.

To the extent a resource is moved away from its Dispatch Operating Point (DOP) by AGC or any uninstructed deviation, the RTM will dispatch the resource from its current output assuming that it will return to its DOP as soon as possible

To the extent that such a resource deviates from its DOP due to regulating action of AGC, the imbalance Energy produced or consumed (relative to the DOP) is attributed to Regulation and

paid as Instructed Imbalance Energy as described in Section 11.5.1. However, such imbalance Energy is not eligible for RTM Bid Cost Recovery as provided in Section 11.8.4 of the CAISO Tariff.

4.2.6 Regulation Up & Down Requirements

A minimum requirement for Regulation Up capacity and a minimum requirement for Regulation Down capacity can be specified for each AS Region and each Trading Hour. In addition, there is a Mileage requirement for Regulation Up and Regulation Down, representing the expected amount of system-wide resource operating point travel required to provide the service. Separate requirements are created for Regulation Up and Regulation Down, and are enforced at the Expanded System Region only. Finally, there is a maximum requirement for all upward AS collectively. Both Regulation Bids and Regulation self-provisions can participate in meeting these requirements. Only on-line Generating Units can be awarded Regulation service to contribute to the Regulation Up and Regulation Down requirements.

CAISO sets its Regulation reserve target as a percentage of CAISO Forecast of CAISO Demand for the hour based upon its need to meet the WECC and NERC performance standards (primarily CPS1 and CPS2). However, the percentage targets can be different for Regulation Up and Regulation Down. The percentage targets can also vary based on the hour of the Operating Day. CAISO's Regulation targets (in MWh) may change if its Demand Forecast changes after running the Day-Ahead Market.

For each hour, the Mileage procurement requirement is calculated as the lower of three values:

1) The product of each regulating service's capacity requirement and a System Mileage Multiplier for that service and hour. The System Mileage Multiplier is the amount of total expected generator movement (up or down), or Mileage, from 1 MW of Regulation Up or Down capacity. CAISO calculates an hourly System Mileage Multiplier from the measurement of Mileage of the prior 7 days for each hour. For example, if the regulation up capacity procurement target for a given hour is 350MW, and the System Mileage Up Multiplier is 3.61, the mileage procurement target would be 1263 MW (350 x 3.61).

2) The average hourly actual mileage from the prior 7 days for that hour. This is calculated as the total mileage for the relevant hour divided by 7.

3) The sum of the product of each resource's resource-specific Mileage multiplier and the resource bid-in regulation capacity. This number represents the total Mileage capability of the resources that have bid into the market. Inclusion of this number prevents a potential Mileage scarcity situation.

CAISO may adjust the mileage requirement based on operational needs.

See Appendix Attachment J for more details on the calculation of the System Mileage Multiplier and the resource-specific Mileage multiplier.

4.2.7 Operating Reserve Requirements

This section is based on CAISO Tariff Section 8.2.3.2.

CAISO sets its procurement target in accordance with WECC Minimum Operating Reliability Criteria (MORC) requirements. Currently, based on these standards, CAISO procures Operating Reserves equal to the maximum value of:

- The sum of three percent of hourly integrated load plus three percent of hourly integrated generation, or
- The sum of a pre-selected list of photovoltaic resources multiplied by a percentage value[22]
- Load Forecast based requirements[23]
- The single largest Contingency

CAISO follows these requirements or whatever other NERC or WECC standards may replace them.

Cascading is the procurement of upward AS by substituting a higher quality AS type to meet the requirement of a lower quality AS type if it is economically optimal to do so in the co-optimization process. Cascading of AS procurement does not occur in the portion of the AS Self-Provision Qualification Process that takes place before SCUC. The hierarchy of evaluating

[22] This requirement is based upon the loss of all solar resources with earlier-based inverters in certain voltage fluctuation situations. Based upon the studied and observed occurrences, this Ancillary Service procurement target may be equal or greater than 15% of the hourly sum of all the solar resources at-risk forecast.

[23] In practice, the former (quantity of Operating Reserves based on percentage of CAISO Demand) is greater in most hours and sets the requirements system-wide. However, if CAISO must target procurement of Operating Reserves on a more granular basis, such as sub-AS Regions, the CAISO would determine the regional requirements considering the factors stated in Section 8.3.3.2 of the CAISO Tariff and discussed in Section 4.2 of this BPM. Because the single largest Contingency may affect these factors more in an AS Sub-Region than in the CAISO as a whole, the latter criteria (quantity of Operating Reserves based on the single largest Contingency) could affect the procurement of Operating Reserves in one or more of the smaller regions.

AS types in the cascaded AS procurement in the co-optimization process, from highest to lowest, is as follows:

- Regulation Up
- Spinning Reserve
- Non-Spinning Reserve

This substitution only occurs if the substituting resources are eligible to provide the lesser valuable service as provided in Section 8.2.3.5. Moreover, for example, if Regulation was used to meet the requirement of a lower quality AS type like Spinning Reserve, and CAISO ends up Dispatching Energy from that Capacity, the Energy will be treated as Energy from Regulation. The Regulation that was substituted from the Spinning Reserve will be settled as the need for which it was actually used, *i.e.*, the Regulation (Section 11.10.2 of the CAISO Tariff), and in addition the associated delivered Energy will be paid as Instructed Imbalance Energy (Section 11.5.1 of the CAISO Tariff) and as provided in Section 11.8.4 of the CAISO Tariff will not set LMP and will not be eligible for RTM Bid Cost Recovery.

The quantities of Regulation Up, Regulation Down, and Operating Reserves that CAISO targets for each hour of the Operating Day are published as part of the public market information by 1800 hours two days prior to the Trading Day. Total system AS requirement is also posted to OASIS.

4.2.7.1 Spinning Reserve Requirements

Separate Spinning Reserve minimal requirements are specified for each AS Region and for each Trading Hour. The Spinning Reserve requirements can be met by Spinning Reserve Bids and Spinning Reserve self-provision, as well as Regulation Up Bids. Only on-line Generating Units (and eligible System Resources) provide Spinning Reserve service. According to Ancillary Service cascading, Regulation Up can be used as Spinning Reserve after the Regulation Up requirement is met.

When cascading methodology results in awarding Regulation Up capacity to satisfy a portion of the Spinning Reserve requirement, this capacity is not treated as Spinning Reserve. The capacity retains the Regulation Up designation. As such, the Regulation Up Award does not require an Energy Bid to be dispatched in Real-Time by AGC.

4.2.7.2 Non-Spinning Reserve Requirements

Separate Non-Spinning Reserve minimum requirements can be specified for each AS Region for each Trading Hour. Bids for Regulation Up and Spinning Reserve can also be counted as Non-Spinning Reserve. The Non-Spinning Reserve requirements can be met by Non-Spinning

Reserve Bids and Non-Spinning Reserve self-provision as well as Regulation Up and Spinning Reserve Bids.

4.2.8 Maximum Upward Capacity Constraint

The total amount of upward Ancillary Service capacity may be limited for each AS Region. Specifically, the sum of Regulation Up, Spinning Reserve, and Non-Spinning Reserve procured in each AS Region using Bids or self-provision cannot exceed a maximum capacity limit at any time interval.

The purpose of enforcing a maximum procurement limit on an AS Region is to minimize the likelihood of a condition where too much AS capacity is allocated to resources in an AS Region where Energy supply limitations, due to Transmission or other constraints, are expected.

4.2.9 Ancillary Service Constraints for Storage Resources

The ISO implements a series of constraints related to the impact of ancillary service awards on state of charge on storage resources. The intent is to better capture the potential impact of ancillary service awards on the state charge within the market dispatch as well as to increase the feasibility of ancillary service market awards.

4.2.9.1 Parameter Definitions

This section defines all of the parameters used in the equations in this section.

i	Resource index
t	Time interval index
$E^{(+)}$	Discharging energy schedule (positive, 0 if not discharging)
η	Round trip efficiency
$E^{(-)}$	Charging energy schedule (negative, 0 if not charging)
RU	Regulation up award
mRU	Multiplier applied to regulation up (between 0 and 1)
RD	Regulation down award
mRD	Multiplier applied to regulation down (between 0 and 1)
u	Resource index

$\bar{P}$	Maximum discharge capability
$\underline{P}$	Minimum charge capability (negative)
E	Energy schedule
SR	Spinning reserve award
NR	Non-spinning reserve award
SOC	State of charge
SOC^{AT}	State of charge including attenuation factors
$\underline{SOC}$	Minimum state of charge
$\overline{SOC}$	Maximum state of charge
ΔT	Duration of real-time interval (15 or 5 minutes)
T	One hour
FRU	Upward flexible ramping product award
FRD	Downward flexible ramping product award
mAS	Multiplier applied to ancillary service capacity awards (between 0 and 1)
UEL	Upper economic limit
LEL	Lower economic limit
S_{LESR}	Set of limited energy storage resources (LESR).
IRU	Imbalance Reserve Up
IRD	Imbalance Reserve Down

Storage resources that provide ancillary services must have sufficient state of charge to assure that ancillary service awards are deliverable. This can result in optimal energy schedules that include charging in the day-ahead market in preparation for ancillary service awards, or charging in the real-time market during intervals when a storage resource has ancillary service awards. A storage resource also may be required to charge in advance of hours with awards

for ancillary services to ensure sufficient state of charge to meet the ancillary service state of charge constraints.

Energy schedules and ancillary service awards are co-optimized in the day ahead and FMM markets and are subject to these SOC constraints. The ancillary service awards are fixed in RTD; however, the SOC constraints are still enforced in RTD to constrain the energy dispatch so that the sustained energy requirement is satisfied, and to ensure future awards and self-schedules can be met.

In day ahead, storage resources are subject to ancillary service SOC constraints and envelope constraints. The ancillary service SOC constraints ensure adequate SOC to cover all energy, ancillary services, and capacity products in each hour, while the upper and lower envelope constraints track the impact to the SOC of providing these services over the course of the day, and ensure all hours maintain sufficient SOC to meet the awards. See section 6.6.2.3 for more detailed information on these constraints in day ahead.

In the real-time markets, storage resources are subject to ancillary service SOC constraints and the SOCAT constraints. The ancillary service SOC constraint ensures sufficient SOC to cover all energy, ancillary services, and flexible ramping awards in each interval. The SOCAT constraint tracks the impact of providing these awards over course of the market run, ensuring the resource has sufficient SOC in all intervals to meet the awards. See section 7.8.2.5 for more detailed information on these constraints in the real-time markets.

~~**4.2.9.2 State of charge equation with ancillary service impact in the day ahead market**~~

$$\left.\begin{aligned}
SOC_{i,t} &= SOC_{i,t-1} - \left(EN_{i,t}^{(+)} + \eta_i EN_{i,t}^{(-)}\right)\frac{\Delta T}{T_{60}} \\
\underline{SOC_{i,t}} &\le SOC_{i,t} \le \overline{SOC_{i,t}} \\
SOC_{i,t}^{AT} &= SOC_{i,t-1}^{AT} - \left(EN_{i,t}^{(+)} + \eta EN_{i,t}^{(-)} + ATRU_t RU_{i,t} - ATRD_t \eta_i RD_{i,t}\right)\frac{\Delta T}{T_{60}} \\
\underline{SOC_{i,t}^{AT}} &\le SOC_{i,t}^{AT} \le \overline{SOC_{i,t}^{AT}} \\
0 &\le EN_{i,t}^{(+)} \le u_{i,t} UEL'_{i,t} \\
(1 - u_{i,t}) LEL'_{i,t} &\le EN_{i,t}^{(-)} \le 0 \\
EN_{i,t,} &= EN_{i,t}^{(+)} + EN_{i,t}^{(-)} \\
u_{i,t} &= \{0,1\}
\end{aligned}\right\}, \forall i \in S_{LESR} \wedge t$$

~~Both $SOC_{i,t}^{AT}$ and $SOC_{i,t}$ constraints are enforced and must be simultaneously feasible within any market solution. Simultaneous feasibly serves to limit pricing linkages between the conversion of regulation awards to SOC that can later be dispatched via energy awards, reducing the potential for undesirable regulation down pricing outcomes.~~

The influence of regulation on the projected state of charge (SOC) is modeled through the regulation awards and the multipliers projecting the typical impacts of regulation up and regulation down on SOC. The attenuation factors, or multipliers are determined based on the historical usage of regulation from the corresponding period of the previous year. Since the use of regulation may exhibit a seasonal pattern, the multipliers will be estimated for each calendar quarter and updated prior to the start of the quarter. The values are posted under section *Attenuation factors for regulation* on page Network and Resource Modeling.

~~4.2.9.3~~4.2.9.2 Ancillary Service State of Charge Constraint

Section 8.4.1.1(g) of the tariff requires that Regulation capacity offered must be dispatchable on a continuous basis for at least sixty (60) minutes in the Day-Ahead Market and at least thirty (30) minutes in the Real-Time Market after issuance of the Dispatch Instruction. The CAISO will measure continuous Energy from the time a resource reaches its award capacity. In the Real-Time Market, where a storage resource using the Non-Generator Resource model will not have sufficient State of Charge to meet its Ancillary Services Schedule, the CAISO will dispatch the storage resource to have sufficient State of Charge to meet its Ancillary Services Schedule.

The CAISO enforces this requirement through the ancillary service state of charge constraint. It ensures that storage resources awarded ancillary services have one hour of state of charge during any hour when they receive awards in the day-ahead market. The following equation reflects the ancillary service state of charge constraint in the day-ahead market:

$$\underline{SOC}_{i,t} + \left(RU_{i,t} + SR_{i,t} + NR_{i,t} + IRU_{i,t}\right) \leq SOC_{i,t} \leq \overline{SOC}_{i,t} - \eta_i\left(RD_{i,t} + IRD_{i,t}\right)$$

~~$$\underline{SOC}_{i,t} + \left(RU_{i,t} + SR_{i,t} + NR_{i,t}\right) \leq SOC_{i,t} \leq \overline{SOC}_{i,t} \quad \eta_i\left(RD_{i,t}\right)$$~~

This constraint essentially states that a storage resource must have at least one hour of state of charge to provide all awarded ancillary services and imbalance reserves ~~regulation service~~ for that specific hour and be within the minimum and maximum state of charge at the end of the hour after providing the service. For example, assuming that the minimum SOC is 0 MWh, this constraint will ensure that a storage resource with a 10 MW award for regulation up during a

specific hour has at least 10 MWh of energy to provide the 10 MW regulation award for that hour and be at the minimum SOC limit at the end of that hour.

In the real-time market the ancillary service state of charge constraint ensures that storage resources have at least 30 minutes of state of charge while providing ancillary services, and 15-minutes or 5-minutes of state of charge while providing flexible ramping capability.

The following equations reflect these constraints

$$\underline{SOC_{i,t}} + \frac{1}{2}\left(SR_{i,t} + RU_{i,t} + NR_{i,t}\right) + \frac{\Delta T}{T} FRU_{i,t} \leq SOC_{i,t} \leq \overline{SOC_{i,t}} - \eta_i \frac{1}{2} RD_{i,t} - \eta_i \frac{\Delta T}{T} FRD_{i,t}$$

In the real-time market, these constraints can result in charging awards or discharging awards for storage resources. For example, if the real-time market models that a storage resource will only have 4.8 MWh of state of charge, it will issue an award for energy to charge the resource so that it has at least 5.0 MWh of energy for every interval that the resource is awarded 10 MW of regulation. When these constraints bind, and result in energy awards, storage resources are not eligible for bid cost recovery.

In Real-Time Contingency Dispatch (RTCD) and in Real-Time Disturbance Dispatch (RTDD) the market application will release the state of charge to deliver Spin and Non-Spin capacity for 10 minutes but continue to reserve the state of charge to ensure deliverability of Spin and Non-Spin capacity for future RTCD and RTDD. In subsequent RTCD and RTDD market runs, the application will release all state of charge to deliver Spin and Non-Spin capacity. In all RTCD and RTDD market runs, the market application will reserve the state of charge for 30 minutes to support deliverability of Regulation Up and Regulation Down capacity. In the event that a specific resource does not have sufficient state of charge prior to an ancillary service award or qualified self-provision in any fifteen-minute market interval, the CAISO may procure incremental ancillary services from another resource. In this event, the resource with an insufficient state of charge will be subject to the CAISO's payment rescission rules.

The state of charge equation with ancillary service impact and the ancillary service state of charge constraint are simultaneously enforced along with the state of charge equation in the day ahead and real time markets as outlined in sections 6.6.2.3 and 7.8.2, respectively.

~~4.2.9.4~~4.2.9.3 Ancillary Service Award Constraints

To ensure these requirements are met, storage resources providing ancillary services in positive direction are required to bid energy in the opposite direction (charging energy). The corollary

requirement also applies to require storage resources provide bids for discharging energy while awarded ancillary services in the negative direction. To enforce the requirement, SIBR will auto-populate this real-time bid where a scheduling coordinator fails to do so.

In theory, a storage resource could have the ability to provide regulating service from a minimum operating level to maximum operating level. However, this would result in situations where the market optimization could not dispatch a resource carrying an ancillary service for energy. To avoid this, the day-ahead market includes additional restrictions on the amount of ancillary service capacity it will award to any storage resource.

$$-\underline{P}_{i,t} - RD_{i,t} \geq mAS\left(RU_{i,t} + SR_{i,t} + NR_{i,t}\right)$$
$$\overline{P}_{i,t} - RU_{i,t} - SR_{i,t} - NR_{i,t} \geq mAS\ \left(RD_{i,t}\right)$$

The first equation ensures that the negative (charging) capacity, excluding capacity already set aside for regulation down, is greater than some fraction of the regulating services in the upward direction. The second equation sets the corollary requirement.

Ancillary services awards in real time require an energy bid in the opposite direction. Ancillary services awards are also constrained to reserve a portion for charging and discharging the LESR to achieve the SOC level needed to meet the real time ancillary services awards in case there are SOC deviations. This is achieved using the equations below.

$$mAS\left(RU_{i,t} + SR_{i,t} + NR_{i,t}\right) \leq -\underline{P}_{i,t} - RD_{i,t}$$
$$mAS\left(RU_{i,t} + SR_{i,t} + NR_{i,t}\right) \leq \max\left(0, -LEL_{i,t}\right)$$
$$mAS\ RD_{i,t} \leq \overline{P}_{i,t} - RU_{i,t} - SR_{i,t} - NR_{i,t}$$
$$mAS\ RD_{i,t} \leq \max\left(0, UEL_{i,t}\right)$$

For example, a storage resource with an award for 10 MW of regulation up must bid 5 MW of charging energy into the real-time market. Conversely a storage resource with a 10 MW of regulation down must bid 5 MW of discharge energy into the real time market.

Parameters Values:

mAS	The ancillary service multiplier is 0.5

The ancillary service multiplier is based on the tariff requirement that storage resources must be able to provide ancillary service at least thirty (30) minutes in the Real-Time Market after issuance of the Dispatch Instruction. It allows for sufficient capacity to bid energy for charging or discharging when a storage resource is awarded ancillary services in the day-ahead market. This multiplier effectively sets the minimum threshold for bids for energy that storage resources

could make and that the market could call on in the real-time market. Setting the requirements too low could result in scenarios where storage resources do not have capacity that could be called on for energy in the real-time market and could also result in an inability for the market to ensure the ancillary service state of charge requirements.

~~4.2.9.5~~4.2.9.4 Regulation Energy Management

Storage resources have the ability to operate using the regulation energy management (REM) functionality. This functionality allows resources to only provide regulating services, both in the upward and downward directions, and precludes participation in the energy market. This functionality manages state of charge with functionality built into the automatic generation control (AGC). This state of charge management functionality:

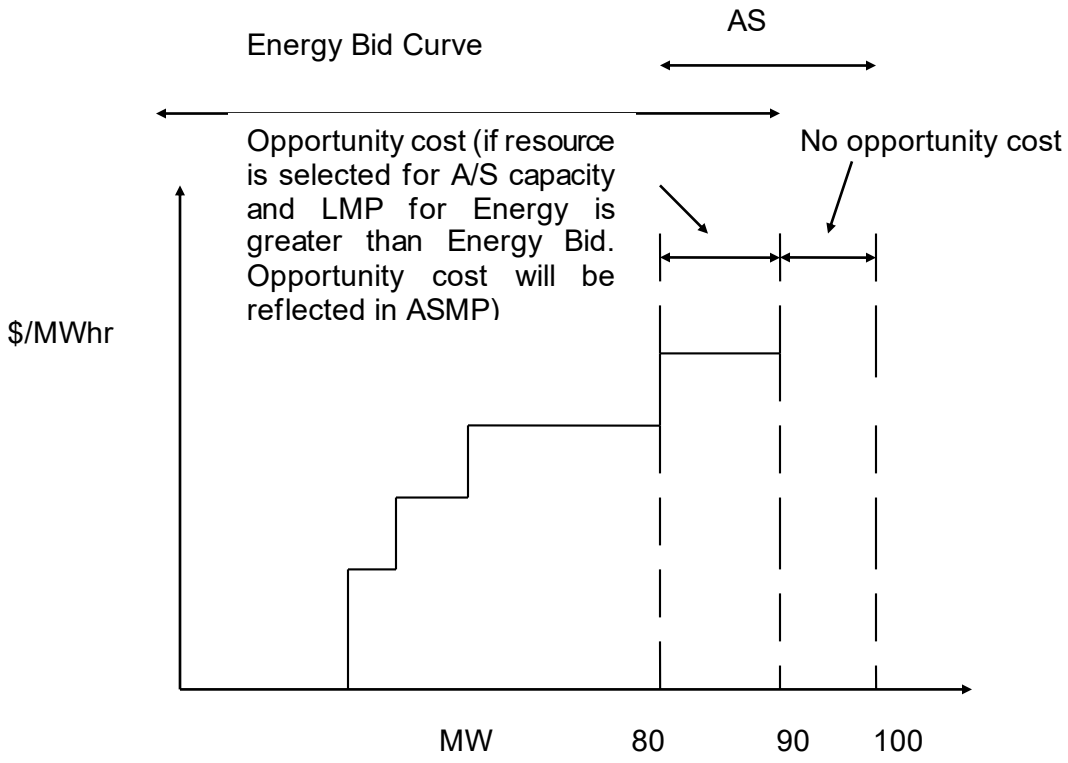
- Maintains the state of charge at 50 percent if system conditions are normal and grid reliability is not threatened by doing so.
- If the state of charge is below 50 percent and there are regulation down needs, the automatic generator control instructions will instruct the resource to charge.
- If the state of charge is above 50 percent and there are regulation up needs, the automatic generator control will instruct the resource to discharge.

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 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 CAISOBAA 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 Bidsthese bids is optimally used for an Energy schedule, or it is reserved for AS in the form of AS or Imbalance Reserve 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, AS capacity, and ASImbalance Reserve capacity can be accomplished by assigning the same Congestion cost to each commodity. This process allows Energy, AS capacity, and ASImbalance 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, AS capacity, and ASImbalance

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.

4.3.2 Ancillary Services Procured in Real-Time

- Ancillary Services are procured in the Real-Time Market from resources internal to the ISO system and System Resources that do not submit HASP Block Intertie Schedules, through the FMM process, as needed to satisfy the NERC requirements. []

- Ancillary Services are procured on an hourly basis in the HASP from Non-Dynamic System Resources that submit Hourly Block Bids.

Ancillary Services Awards for all resources except Non-Dynamic System Resources that submit Hourly Block Bids are only considered binding the first 15-minute interval of each FMM run. Ancillary Service Awards from Non-Dynamic System Resources that submit Hourly Block Bids that are procured in the HASP are considered binding for the HASP Trading Hour. The resources that are committed in Real-Time to provide Imbalance Energy and/or AS are eligible for Start-Up and Minimum Load Cost compensation, except for Non-Resource Specific System Resources.

CAISO procures additional ancillary services in the 15-minute market from resources that are certified to provide these services.

Refer to Section 7.6.2, Real-Time Ancillary Services Procurement, for additional information.

4.3.2.1 Regulation

CAISO can procure Regulation in RTM from resources which are available and offer Regulation and Mileage bids in RTM. WECC allows Regulation to be used for Spinning Reserve. Although Regulation Up won't necessarily be used as spin, it does count to ensure that there are sufficient Operating Reserves available.

4.3.2.2 Spinning & Non-Spinning Reserve

This section is based on CAISO Tariff Section 31.5.6.

Real-Time procurement and pricing of Spinning Reserve and Non-Spinning Reserve is performed using dynamic co-optimization of Energy and Spinning and Non-Spinning Reserve. Spinning Reserve and Non-Spinning Reserve procured in Real-Time are for Contingency Only.

These requirements are calculated as part of the RTM based on the Demand Forecast and can be adjusted by the CAISO Operator.

4.3.3 Manual real-time contracting for ancillary services or unloaded resource capacity

In addition to procuring Ancillary Services through the day-ahead market and fifteen minute market, the CAISO may enter into real-time contracts for ancillary services and unloaded resource capacity. These contracts are necessary at times to ensure the CAISO maintains sufficient reserves over each clock hour to comply with Applicable Reliability Criteria. For example, if a need arises after the last Fifteen Minute Market run can secure sufficient reserves within an operating hour then the CAISO may elect to take an out of market action to maintain adequate reserves. This need can arise from changes in operating conditions such as loss of generation or transmission.

If a real-time need for ancillary services arises that the market cannot resolve, the CAISO may contact scheduling coordinators in order to secure ancillary services or unloaded resource capacity to serve as contingency reserves. As part of this practice, the CAISO may secure Ancillary Services or unloaded resource capacity from Reliability Must Run units. If this capacity is not available, the CAISO may contact scheduling coordinators to secure Ancillary Services or unloaded resource capacity from resource adequacy resources or, if necessary, non-resource adequacy resources. The CAISO considers various inputs as part of this real-time contracting process, including, among others, available bid-in Ancillary Services, bid price, ramp rates, regulating ranges, outages, minimum run times, number of startups, congestion, telemetry as well as a resource's dispatch operating target. The CAISO will release manually procured reserves once the market has procured adequate Ancillary Services to meet the CAISO's reserve requirements on a going forward basis. When manually procured reserves are no longer needed, the CAISO will contact the scheduling coordinator for the resource to notify it of the time the Ancillary Services is no longer counted in the CAISO's Energy Management System.

Ancillary Services or unloaded capacity that the CAISO manually secures in real-time in any portion of a fifteen-minute clock interval is eligible to receive payment for that fifteen minute clock interval at the applicable FMM ASMP. See Section 4.4 for details of the ASMP payment.

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, 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 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
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, 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.

4.4.1 Ancillary Services Pricing in Event of Supply Insufficiency

In the event that supply is insufficient to meet the minimum reserves procurement requirements in Ancillary Service Region or Sub-region, the scarcity pricing mechanism lets Ancillary Service Marginal Prices in the scarce Region or Sub-region rise automatically to administratively determined values. The mechanism uses a Scarcity Reserve Demand Curve with different pre-determined values at different levels of scarcity. If minimum Ancillary Service requirements of the Expanded System Region and/or Ancillary Service Sub-Regions are not met, the Ancillary Service Shadow Prices corresponding to the supply deficient Ancillary Services in Expanded System Region or Ancillary Service Sub-Region will rise to the Scarcity Reserve Demand Curve Values that reflect the level of shortage. The Ancillary Service Marginal Price of a higher quality reserve will always be higher than or equal to the price of a lower quality reserve in the same Ancillary Service Region or Sub-region. Also, the Ancillary Service Marginal Price of a reserve in a sub-region will always be higher than or equal to the price of the same reserve in the outer sub-region or Expanded System Region. The CAISO will consider the System Region as a Sub-Region for the purposes of Ancillary Service pricing in case of supply insufficiency.

4.4.1.1 Scarcity Reserve Demand Curve

The CAISO will use Scarcity Reserve Demand Curves to set the administrative values for Ancillary Service Marginal Prices in supply shortage conditions. The CAISO will use a tiered demand curve for the three upward reserves i.e. Spinning Reserve, Non-Spinning Reserve and Regulation Up Service and a separate tiered demand curve for Regulation Down Service. The CAISO defines Scarcity Reserve Demand Curve Values, as shown in the exhibit below, as percentages of the maximum energy bid price set forth in Tariff Section 39.6.1.1:

Exhibit 4-5: Scarcity Reserve Demand Curve Values

Reserve	Demand Curve Value ($/MWh)		
	Percent of	Max Energy Bid Price	Max Energy Bid Price

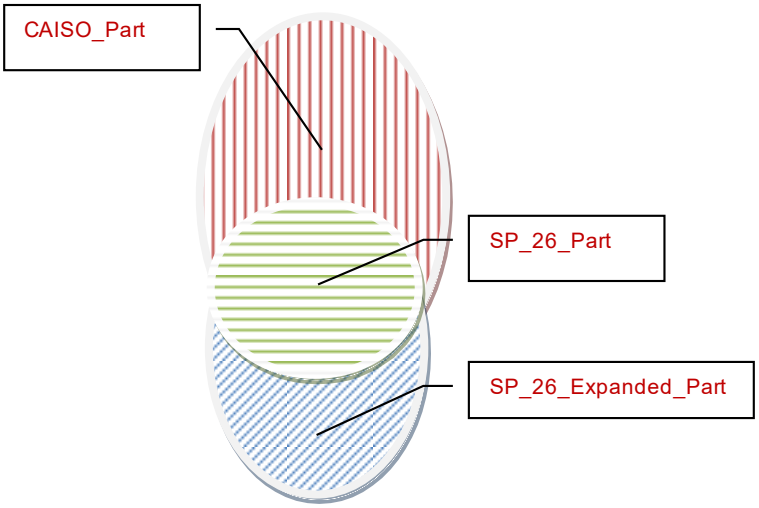
	Max Energy Bid Price		= $750/MWh		= $1000/MWh	
	Expanded System Region	System Region and Sub-Region	Expanded System Region	System Region and Sub-Region	Expanded System Region	System Region and Sub-Region
Regulation Up	20%	20%	$150	$150	$200	$200
Spinning	10%	10%	$75	$75	$100	$100
Non-Spinning						
Shortage > 210 MW	70%	70%	$525	$525	$700	$700
Shortage > 70 & < = 210 MW	60%	60%	$450	$450	$600	$600
Shortage □ 70 MW	50%	50%	$375	$375	$500	$500
Upward Sum	**100%**	**100%**	**$750**	**$750**	**$1,000**	**$1,000**
Regulation Down						
Shortage > 84 MW	70%	70%	$525	$525	$700	$700
Shortage > 32 & < □ 84 MW	60%	60%	$450	$450	$600	$600
Shortage □ 32 MW	50%	50%	$375	$375	$500	$500

4.4.1.2 Ancillary Services Sub-Regional Partitions

According to the CAISO tariff, the Scarcity Reserve Demand Curve Value will not be double-counted in the calculation of Ancillary Service Marginal Prices when there is scarcity in a sub-region. For that purpose the CAISO will enact Ancillary Service sub-regional partitions when there is Ancillary Service scarcity in one or more Ancillary Service Sub-Regions.

For example, all internal resources in SP-26 are contained in SP_26_Expanded as well as the CAISO (not CAISO_Expanded) Ancillary Service sub-regions. However, the intertie resources in SP_26_Expanded are not part of the CAISO Ancillary Service Sub-Region. Instead, they are part of the CAISO Expanded System Region. This situation creates overlapping (not total nesting) of Ancillary Service Sub-Regions. When scarcity occurs in the scheduling run in SP_26, the CAISO will separate SP_26 from SP_26_Expand to form two partitions: SP_26_Part, which is the geographic footprint of SP_26 Sub-region and SP_26_Expand_Part, which is the part of SP_26_Expand not overlapping with SP_26. The CAISO will also separate SP_26_Part from the CAISO Sub-region to create another partition CAISO_Part, which is the part of CAISO that does not overlap with SP_26.

The CAISO will use non-overlapping Ancillary Service partitions to establish Ancillary Service procurement requirements. The following figure provides an illustration of the partition concept using the SP_26, SP_26_Expanded and CAISO System Regions.



Non-Overlapping Partitions of the Ancillary Service Sub-Regions

The ISO calculates Ancillary Service Marginal Prices in a Sub-Region as the sum of shadow prices of Ancillary Service procurement requirement constraint in the Sub-Region and the Region in which the Sub-Region nests. To make this calculation explicit to market participants, the CAISO may adjust the calculated Ancillary Service Shadow Prices of the scarce sub-region partitions and publish the adjusted shadow prices on the CAISO OASIS.

The published pricing run adjusted Shadow Prices, λ_{adj}, for each of the Ancillary Service reserves in the scarce Ancillary Service partition shall be calculated as the maximum of zero, and the difference between the Shadow Price of the Ancillary Service reserve in the scarce partition and the Shadow Price of the same Ancillary Service reserve in the CAISO_Expand constraint, i.e. $\lambda^{adj}{}_{partition,As} = \max(0, \lambda_{partition,AS} - \lambda_{system,AS})$. The adjusted Shadow Prices shall be used for the calculation of the resources' Ancillary Service Marginal Prices. The calculations of the Ancillary Service Marginal Price on a resource level will continue to follow the same calculation rule of summing all Shadow Prices for all Ancillary Service constraints (whether Ancillary Service region/sub-region or Ancillary Service partition) in which the resource is participating. For example, resources in the SP_26 Ancillary Service Sub-Region participate in the SP_26 Ancillary Service Sub-Region, the CAISO System Region, and SP_26_Part Ancillary Service

partition, but not in the CAISO_Part Ancillary Service partition constraint nor in SP_26_Expanded_Part Ancillary Service partition constraint.

4.4.1.3 Examples of Ancillary Service Marginal Price calculation

This section provides examples of calculating Ancillary Service Marginal Prices in a supply insufficiency situation. For the purpose of these examples, it is assumed that there is only one Ancillary Services Sub-Region which is nested within the Expanded System Region. These examples reflect various scenarios from the shortage of one reserve in the Expanded System Region to shortage of all Ancillary Services in Expanded System Region and Sub-Region. Some of the scenarios are unlikely to occur in actual market operation. They are provided in this document to illustrate how the ISO will calculate Ancillary Service Marginal Prices when a scarcity condition occurs. The Ancillary Service shadow prices in the scarce sub-regions and partitions are adjusted based on the method described in section 4.4.1.2 of this document.

Example 1:

This example demonstrates the calculation of Ancillary Service Marginal Prices for various reserves in case of a shortage in Non-Spinning Reserve greater than 210 MW in the Expanded System Region when the maximum energy bid price is $1,000/MWh. In this example, the Ancillary Service Shadow Price for Non-Spinning Reserve in the Expanded System Region is $700/MWh, determined by the demand curve value with $1000/MWh maximum energy bid price. The Ancillary Service Marginal Prices for all reserves in the Expanded System Region and sub-region are shown in the exhibit below.

Please note that the Ancillary Service Marginal Prices of all three Ancillary Services in the Sub-Region are above the $700/MWh scarcity price in the Expanded System Region. In this example, the Ancillary Service Marginal Prices reflect the opportunity cost of providing energy by the resources in the Sub-Region in addition to the scarcity condition in the Expanded System Region.

Exhibit 4-6: Ancillary Service Marginal Prices in the case of Non-Spinning Reserve shortage in the Expanded System Region

Reserve	Ancillary Service Shadow Price ($/MWh)		Ancillary Service Marginal Price ($/MWh)	
	Expanded System Region	Sub-Region	Resources participating in Expanded System Region but not in Sub-Region	Resources participating in Sub-Region
Regulation Up	700	90	700	790
Spinning	700	50	700	750
Non-Spinning	700	30	700	730
Regulation Down	30		30	

Example 2:

This example demonstrates the calculation of Ancillary Service Marginal Prices for various reserves in case of a shortage in Non-Spinning Reserve greater than 210 MW in the Ancillary Services Sub-Region when the maximum energy bid price is $1,000/MWh. In this example, the Ancillary Service Shadow Price for Non-Spinning Reserve in the Sub-Region will be $ 700/MWh, determined by the demand curve value with $1000/MWh maximum energy bid price. The Ancillary Service Marginal Prices for all reserves are shown in the exhibit below.

Exhibit 4-7: Ancillary Service Marginal Prices in the case of Non – Spinning Reserve shortage in the Ancillary Services Sub-Region

Reserve	Ancillary Service Shadow Price ($/MWh)		Ancillary Service Marginal Price ($/MWh)	
	Expanded System Region	Sub-Region	Resources participating in Expanded System Region but not in Sub-Region	Resources participating in Sub-Region
Regulation Up	150	550	150	700
Spinning	60	640	60	700
Non-Spinning	50	650	50	700
Regulation Down	30		30	

Example 3:

This example demonstrates the calculation of Ancillary Service Marginal Prices for various reserves in case of a shortage in Regulation-Up Reserve in the Expanded System Region when the maximum energy bid price is $1,000/MWh. In this example, the Ancillary Service Shadow Price for Regulation-Up Reserve in the Expanded System Region will be $200/MWh, determined by the demand curve value with $1000/MWh maximum energy bid price. The Ancillary Service Marginal Prices for all reserves shown in the exhibit below.

Exhibit 4-8: Ancillary Service Marginal Prices in the case of Regulation-Up Reserve shortage in the Expanded System Region

Reserve	Ancillary Service Shadow Price ($/MWh)		Ancillary Service Marginal Price ($/MWh)	
	Expanded System Region	Sub-Region	Resources participating in Expanded System Region but not in Sub-Region	Resources participating in Sub-Region
Regulation Up	200	90	200	290
Spinning	60	50	60	110
Non-Spinning	50	30	50	80
Regulation Down	30		30	

Example 4:

This example demonstrates the calculation of Ancillary Service Marginal Prices for various reserves in case of a shortage greater than 210 MW of Non-Spinning Reserve and a shortage in Regulation-Up shortage in the Expanded System Region when the maximum energy bid price is $1,000/MWh. In this example, the Ancillary Service Shadow Price for Regulation-Up in the Expanded System Region will be $200/MWh, determined by the demand curve value with $1000/MWh maximum energy bid price. In this example, the Ancillary Service Shadow Price for Non-Spinning Reserve in the Expanded System Region is $700/MWh, determined by the demand curve value with $1000/MWh maximum energy bid price. The Ancillary Service Marginal Prices for all reserves are shown in the exhibit below.

Exhibit 4-9: Ancillary Service Marginal Prices in the case of Regulation-Up Reserve and Non-Spinning Reserve shortage in the Expanded System Region

Reserve	Ancillary Service Shadow Price ($/MWh)		Ancillary Service Marginal Price ($/MWh)	
	Expanded System Region	Sub-Region	Resources participating in Expanded System Region but not in Sub-Region	Resources participating in Sub-Region
Regulation Up	900	90	900	990
Spinning	700	50	700	750
Non-Spinning	700	30	700	730
Regulation Down	30		30	

Example 5:

This example demonstrates the calculation of Ancillary Service Marginal Prices for various reserves in case of a shortage of all Reserves in both Expanded System Region and Sub-Region when the Non-Spinning Reserve shortage in the Expanded System Region is greater than 210 MWs and the Regulation Down shortage is greater than 84 MWs when the maximum energy bid price is $1,000/MWh. In this example, the Ancillary Service Shadow Prices for all reserves are determined by the demand curve values with $1000/MWh maximum energy bid price. The Ancillary Service Marginal Prices for all reserves are shown in the exhibit below.

Exhibit 4-10: Ancillary Service Marginal Prices in the case of shortage of all Reserves in both Expanded System Region and Sub-Region

Reserve	Ancillary Service Shadow Price ($/MWh)		Ancillary Service Marginal Price ($/MWh)	
	Expanded System Region	Sub-Region	Resources participating in Expanded System Region but not in Sub-Region	Resources participating in Sub-Region
Regulation Up	1000	0	1000	1000
Spinning	800	0	800	800
Non-Spinning	700	0	700	700
Regulation Down	700		700	

4.4.1.4 Impact on Energy Price

In a situation of Ancillary Service supply shortage, Ancillary Service shadow prices will be set by the Scarcity Reserve Demand Curve Values. The energy prices may either rise together with the Ancillary Service prices, or may be unaffected by the increase in Ancillary Service prices. If a generating unit backs down its schedule of an Ancillary Service that is scarce in order to provide one additional MW of energy, the price of energy will include the opportunity cost of the scarce capacity, i.e. the shadow price of the Ancillary Service constraint set by the Scarcity Reserve Demand Curve Value, as well as the bid price of the incremental energy.

4.4.1.5 Ancillary Service Supply Insufficiency Notification

The ISO will issue a Market Notice to inform Market Participants if a scarcity condition occurs.

4.5 Ancillary Services Considerations

This section identifies important considerations in the use and procurement of Ancillary Services, including:

- The Operating Reserve Ramp Rate for Energy within the AS capacity is a single Ramp Rate, which is distinct from the Operational Ramp Rate, and is the same for Spinning and Non-Spinning Reserve.

- Energy Limits of resources bidding into the AS market can be managed by the use of the Contingency Only designation supplied by the SC in the AS Bid. The Contingency Only designation applies for the entire Trading Day. In Real-Time, Energy from Contingency Only Operating Reserves is only cleared against Demand only under Contingency situations.

- Day-Ahead SC trades of Ancillary Service Obligations are supported; however, physical trades of Ancillary Services capacity is not.

- Day-Ahead SC trades of Ancillary Service Obligations are supported; however, physical trades of Ancillary Services capacity is not.

- Forbidden Operating Regions may limit the procurement of Ancillary Services. Specifically, the procurement of Regulation Up, Spinning Reserve, and Non-Spinning Reserve may be limited by the lower bound of a Forbidden Operating Region, and the procurement of Regulation Down may be limited by the upper bound of a Forbidden Operating Region. For the hourly DAM AS procurement, a resource must be able to cross its FOR within 20 minutes in order to be eligible to provide AS for that Trading Hour. For RTM AS procurement, unless a resource can complete the crossing of its FOR within the relevant 15 minute interval, it is ineligible to provide AS and will thus not be called upon to provide AS for that interval., .

- Ancillary Services are not procured from Multi-Stage Generating Resources during a transition between MSG Configurations in both the Day-Ahead Market and Real-Time Market. Also, during the period in which the FMM determines that a Multi-Stage Generating Resource is in transition from one configuration to another, any Day-Ahead Ancillary Service Award or Real-Time Self-Provided Ancillary Services will be disqualified. To determine the exact transition period, the Transition Time adheres to the following rounding method:

    1. Day-Ahead Market--Transition Time of any resource with a value of X hours plus 7.5 minutes or more will be rounded to X+1 hours and any Transition Time of X hours plus less than 7.5 minutes will be rounded to X hours;

    2. Real-Time Unit Commitment--Transition Time of any Multi-Stage Generating Resource with a value of X number of 15 minute intervals plus 7.5 minutes or more will be rounded to X+1 number of 15 minute intervals and any Transition Time of X number of 15 minute intervals plus less than 7.5 minutes will be rounded to X number of 15 minute intervals;

3. Real-Time Dispatch--Transition Time of any Multi-Stage Generating Resource will use the rounded transition time from RTUC.

- Bids to export AS are not supported in the CAISO Markets.

- Export of on-demand obligations of AS are manually supported but cannot be procured from the DAM or RTM.

- All Spinning and Non-Spinning Reserves awarded in the RTM are automatically classified as Contingency Only. Furthermore, any DA Spinning and Non-Spinning Reserve Awards are re-classified as Contingency Only if additional Spinning or Non-Spinning Reserve is awarded in RTM. See CAISO Tariff Section 34.2.2. Any Spinning and Non-Spinning Reserve procured from Non-Dyanmic System Resources are also considered contingency only.

- Any AS designated as Contingency Only is not normally dispatched as Energy in the normal RTED mode. In the Real Time Contingent Dispatch (RTCD) mode, Energy behind Contingency Only AS and non-Contingency Only AS is not distinguished, and is dispatched economically.

- Contingency Only Reserves can also be dispatched by RTED under special circumstances. Section 34.3.2 and 34.8 of the CAISO tariff stipulates the conditions under which the CAISO can dispatch Contingency-Only Reserves.

- Scheduling Coordinators are required to submit an Energy Bid for Non-Dynamic System Resources submitting an Ancillary Services bid in the Real-Time Market. However, the CAISO will only use the Ancillary Service Bid in solving the optimization problem and the associated Energy Bids will not be used in the RTM. The ISO will, therefore, not Dispatch any Energy from the associated Energy Bid if there is no Ancillary Services awarded to the Non-Dynamic System Resource. If the Scheduling Coordinator fails to submit an Energy bid with an Ancillary Services Award, the ISO will generate an Energy bid for the associated Ancillary Services Bid and will not use such Energy bid to Dispatch Energy. See CAISO Tariff Section 30.5.2.6 and the BPM for Market Instruments.

- The Real-Time Market will consider the Unit Operating High Limit and Unit Operating Low Limit as described in Section 8.4.2 of the BPM for Direct Telemetry when awarding Regulation Up and Regulation Down in all intervals of each market run.

4.6 Ancillary Services Certification & Testing Requirements

This section is based on CAISO Tariff Section 8.3.4, Certification and Testing Requirements, and Section 8.4, Technical Requirements for Providing Ancillary Services

Each Generating Unit, System Unit, or Load and PDRs providing load curtailment that are allowed to submit a Bid or AS self-provision under the CAISO Tariff, and each System Resource that is allowed to submit a Bid to provide AS under the CAISO Tariff, must comply with CAISO's certification and testing requirements as contained in the *BPM for Compliance Monitoring*.

RDRR and PDR-LSR consumption resources are not allowed to provide Ancillary Services.

The CAISO certifies Multi-Stage Generating Resources for Ancillary Services at the MSG Configuration level.

CAISO has the right to inspect Generating Units, Participating Loads, PDRs, and PDR-LSR (Curtailment), or the individual resources comprising System Units and other equipment for the purposes of the issue of a certificate and periodically thereafter to satisfy itself that the technical requirements continue to be met. If CAISO has concerns with a resource's ability to provide Ancillary Services and is unable to verify that ability through means listed in the Market Operations and Compliance Monitoring BPMs, the CAISO may initiate a data request to verify how the resource owner is checking, monitoring, and/or testing their system and related equipment as required in Tariff Section 8.9. If at any time CAISO's technical requirements are not being met, CAISO may withdraw the certificate for the Generating Unit, System Unit, Participating Load, PDRs PDR-LSR (Curtailment) or System Resource concerned.[24]

The AS certification and the associated maximum AS capacity are registered in the Master File after testing that demonstrates satisfactory delivery of each AS.

4.6.1 Regulation Certification & Testing Requirements

This section is based on CAISO Tariff Section 8.3.4, Certification and Testing Requirements and Section 8.4.1.1.

Each Generating Unit and System Unit that submits a Bid Regulation or Self-Provides Regulation must be certified and tested by CAISO using the process defined in Part A of

[24] Participating Generators, Participating Loads and Dynamically-Scheduled System Resources are governed by pro-forma Agreements that are included as Appendix B of the Tariff. Each of these Agreements has a Termination clause that permits cancellation of the Agreement under certain conditions, including failure to meet technical requirements. See, for example, Section 3.2.1 of the Participating Generator Agreement.

Appendix K of the CAISO Tariff. Each Dynamic System Resource offering Regulation must comply with the Dynamic Scheduling Protocol in Appendix M of the CAISO Tariff.

Generating Units with Automatic Generation Control capability may be certified for Regulation Up and Regulation Down. Their maximum Regulation Up and Regulation Down capacity is limited to their 10-minute Ramping capability with their best Regulation Ramp Rate.

A resource may lose its ability to provide Regulation if its performance falls below a minimum performance threshold for Regulation Up or Regulation Down. The ISO provides data in CMRI so that Scheduling Coordinators can proactively monitor their unit performance accuracy. If a resource's measured accuracy, based on a weighted average of fifteen-minute intervals during a calendar month using Instructed Mileage as the weight, is less than twenty five percent (25%) for Regulation Up or Regulation Down, the resource has failed to meet the minimum performance threshold. In the event of lost accuracy data, the CAISO will not use data from these intervals to calculate the resource's Historic Regulation Performance Accuracy or to assess the minimum performance threshold.

If a resource fails to meet the minimum performance threshold, the CAISO will provide a warning notice to the resource's Scheduling Coordinator of the resource's failure to meet the minimum performance threshold in the month immediately following the end of the calendar quarter in which the performance failure occurred. Calendar quarter is defined as the periods January-March, April-June, July-September, and October-December. After providing notice to the resource's Scheduling Coordinator, the CAISO will then evaluate the resource's performance in the last two months of the quarter in which the failure notification is provided. If the resource provides at least (15) intervals of the relevant regulation service and meets the minimum performance threshold requirement for both months evaluated, then the warning notice will expire and the resource will be considered as recertified for the service. If the resource provides at least (15) intervals of the relevant regulation service and does not meet the minimum performance threshold for the service for which the failure notice was provided for either of the two months evaluated, the resource will be decertified from providing the service. If a resource does not provide at least (15) intervals of the relevant regulation service in either of the last two months of the quarter in which the failure notification is provided, those months will not be considered. The CAISO will review the resource's performance in subsequent months until the resource provides at least (15) intervals of the relevant regulation service in one calendar month and either meets the minimum performance threshold or does not meet the minimum performance threshold. If the resource meets the minimum performance threshold then the CAISO will re-certify the resource. If the resource does not meet the minimum performance threshold then the CAISO will decertify the resource. Receipt of a warning notice from this process does not preclude resources from undertaking certification testing pursuant to the ISO tariff. If a resource successfully certifies for Regulation during the period following the

month(s) of non-performance and the end of the above referenced evaluation period, the certification shall satisfy the recertification requirement, and any warning notice issued for the month(s) of non-performance shall expire. Decertification resulting from this process does not preclude resources from undertaking certification testing pursuant to the ISO tariff.

Resource-specific System Resources may also be certified for Regulation Up and Regulation Down. Such units must have AGC and dynamic interchange capability to provide Regulation.

Non-generator resources selecting Regulation Energy Management may also be certified for Regulation Up and Regulation down. Using Regulation Energy Management, a NGR maximum Regulation Up and Regulation Down capacity is based on four (4) times the maximum Energy (MWh) the resource can generate or consume for fifteen (15) minutes after issuance of a Dispatch Instruction. Otherwise NGRs selecting Regulation Energy Management must meet the same certification requirements as generators.

For example:

1. A fully charged resource with 5 MWh of energy storage can continuously discharge a maximum 20 MW to the grid for 15 minutes to reach a zero (0) state of charge. If there are no other limitations, the resource will be certified for 20 MW of regulation up capacity. This 20 MW represents four (4) times the 5 MWh discharged in fifteen (15) minutes.

2. A completely discharged resource with 2.5 MWh of energy storage can continuously consume a maximum 10 MW from the grid for 15 minutes to reach a full state of charge. If there are no other limitations, the resource will be certified for 10 MW of regulation down capacity. This 10 MW represents four (4) times the 2.5 MWh consumed in fifteen (15) minutes.

NGRs electing not to use Regulation energy Management will be certified the same as generators.

Examples: The following examples show some of the possible scenarios when a resource does not meet the minimum performance threshold, receives a warning notice and is then evaluated based on the above criteria.

- Example A – For two (2) consecutive months, a resource provides 15 or more intervals of a given regulation service and meets the performance threshold in both months.
- Example B – For two (2) consecutive months, a resource provides 15 or more intervals of a given regulation service and fails to meet the performance threshold in one of those months.

- Examples C & D – A resource provides 15 or more intervals of a given regulation service and meets the performance threshold in one month, then provides less than 15 or more intervals of that same regulation service for a number of months before the next time that the resource provides 15 or more intervals of that given regulation service in a calendar month.

Example	Month	Number of Intervals Provided Regulation	Meet Performance Threshold	Action
A	January			Receives warning notice that resource did not meet the minimum performance threshold during a calendar month(s) in the prior quarter
	February	≥15	Yes	First part of recertification
	March	≥15	Yes	Recertified
Example	**Month**	**Number of Intervals Provided Regulation**	**Meet Performance Threshold**	**Action**
B	January			Receives warning notice that resource did not meet the minimum performance threshold during a calendar month(s) in the prior quarter
	February	≥15	Yes	First part of recertification
	March	≥15	No	Decertified
Example	**Month**	**Number of Intervals Provided Regulation**	**Meet Performance Threshold**	**Action**
C	January			Receives warning notice that resource did not meet the minimum performance threshold during a calendar month(s) in the prior quarter
	February	≥15	Yes	First part of recertification
	March	< 15	Yes	Not used to evaluate performance
	April	< 15	No	Not used to evaluate performance
	May	≥15	Yes	Recertified

Example	Month	Number of Intervals Provided Regulation	Meet Performance Threshold	Action
D	January			Receives warning notice that resource did not meet the minimum performance threshold during a calendar month(s) in the prior quarter
	February	≥15	Yes	First part of recertification
	March	< 15	Yes	Not used to evaluate performance
	April	< 15	No	Not used to evaluate performance
	May	≥15	No	Decertified

4.6.2 Spinning Reserve Certification & Testing Requirements

This section is based on CAISO Tariff Section 8.3.4, Certification and Testing Requirements and Section 8.4.3(a), Ancillary Service Capability Standards

Economic bids or self-provision of Spinning Reserve may be provided only from resources certified to provide Spinning Reserve using the process defined in Appendix K of the CAISO Tariff.

Dispatchable Generating Units may be certified for Spinning Reserve if they can respond to five-minute Dispatch Instructions. Their maximum Spinning Reserve capacity is limited to their operating range from Minimum Load to maximum capacity, or their 10-minute Ramping capability with their best Operational Ramp Rate, whichever is lower.

4.6.3 Non-Spinning Reserve Certification & Testing Requirements

This section is based on CAISO Tariff Section 8.3.4, Certification and Testing Requirements and Section 8.4.3(a), Ancillary Service Capability Standards.

Economic bids or self-provision of Non-Spinning Reserve may be provided from resources certified to provide Non-Spinning Reserve using the process defined in – Parts C of Appendix K of the CAISO Tariff.

Generating Units may be certified for Non-Spinning Reserve if they can respond to five-minute Dispatch Instructions.

- The maximum Non-Spinning Reserve capacity for Generating Units that can start and synchronize with the grid within 10 minutes are limited to the output level they can reach from offline status in 10 minutes, or their 10-minute Ramping capability with their best Operational Ramp Rate, whichever is higher, but not greater than their maximum capacity.

- The maximum Non-Spinning Reserve capacity for other resources that cannot start and synchronize with the grid within 10 minutes are limited to their operating range from Minimum Load to maximum capacity, or their 10-minute Ramping capability with their best Operational Ramp Rate, whichever is lower. In the IFM, Non-Spinning Reserve can be procured from all on-line resources (whether self-committed or committed in the IFM) and from offline Generating Units that can start and synchronize with the grid within 10 minutes.

Only units whose technical characteristics allow them to deliver Non-Spinning Reserve Award within 10 minutes may submit a Bid for Non-Spinning Reserve into RTM.

Units that are already on-line may also offer Non-Spinning Reserve, provided that they are otherwise eligible. However, they may be awarded non-spin only after they shut down.

Participating Load resources may be certified for Non-Spinning Reserve if they can respond to five-minute Dispatch Instructions and can sustain reduced Energy consumption associated with a Non-Spinning Reserve Award for at least thirty minutes.

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

Welcome to the *Existing Transmission Contracts, Converted Rights, & Transmission Ownership Rights* section of the CAISO *BPM for Market Operations*. In this section, you will find the following information:

- A description of the rights and obligations of Non-Participating TOs and PTOs for Existing Rights for transmission under CAISO Operational Control
- How CAISO uses the Existing Transmission Contract Calculator (ETCC)
- The interaction between Transmission Ownership Rights (TORs) in the CAISO Balancing Authority Area and the CAISO
- There are three types of transmission rights in general:
    - Existing Transmission Contracts (ETCs)
    - Converted Rights (CVRs)
    - Transmission ownership rights (TORs)

5.1 Continuation of Rights & Obligations

5.1.1 Existing Transmission Contracts

Existing Transmission Contracts (ETCs) are contractual agreements established prior to the creation of CAISO by which a PTO is obligated to provide transmission service to another party, using transmission facilities owned by the PTO that have been turned over to CAISO Operational Control. An Encumbrance is an Existing Right that an entity, other than a PTO, has on the CAISO Controlled Grid. (CAISO Tariff § 16).

ETCs were created prior to March 31, 1998, when one party to the contract, the PTO, both owned and operated their portion of the transmission grid. After the CAISO became operational, PTOs continue to own their respective portions of the transmission grid but the CAISO is now responsible for the operations of the transmission facilities for which the PTOs transferred their control to the CAISO, including their Entitlements and Encumbrances as defined in the CAISO Tariff and the Transmission Control Agreement Among the Independent System Operator and Transmission Owners, California Independent System Operator Corporation, FERC Electric Tariff No. 7 ("Transmission Control Agreement"). Entitlements consist of those rights on

transmission facilities owned by another entity that the Participating Transmission Owners have obtained by contract or other means to use for their transmission of Energy and Ancillary Services. The cost for transmission service provided under the ETC was negotiated and agreed upon by both parties to the ETC, and then embedded in the terms and conditions of these contracts. The CAISO is not a party to the ETCs. Thus, when CAISO became the transmission operator for the PTO's transmission facilities, the transmission service component of these pre-existing contractual arrangements are honored by granting holders of Existing Rights unique operational and Settlement arrangement, such as the reservation of transmission capacity and exemption from the Access Charge and Congestion Charge associated with such transmission service.

5.1.2 Converted Rights

Converted Rights are transmission rights that are obtained by a party to an ETC that chooses to become a Participating TO and convert its rights to CAISO transmission service. (CAISO Tariff § 4.3.1.6) In the event of such conversion, the Participating TO that is party to the ETC is required to change the terms and conditions of the ETC to provide that:

1) The previously Existing Rights holder under the contract turns over the management of its transmission Entitlement to the CAISO pursuant to the CAISO Tariff and the TCA;

2) The previously Existing Rights holder has converted its rights to CAISO transmission service and shall obtain all service on the CAISO Controlled Grid per the CAISO Tariff;

3) The previously Existing Rights holder shall be entitled to receive the contract cost for the Converted Right in its Transmission Revenue Requirement along with all Wheeling revenue credits throughout the term that the capacity is available under the Existing Contract for the capacity represented by its rights;

4) The previously Existing Rights holder, shall continue to have the obligation to pay the provider of the service for its transmission service at the rates provided in the Existing Contract, as they may change from time to time under the terms of the Existing Contract, or as mutually agreed between the contract parties, through the term of the contract, subject to the terms and conditions of the contract, including the rights of the parties to the contract to seek unilateral or other changes pursuant to Section 205 or Section 206 of the Federal Power Act and the FERC's Rules and Regulations or as otherwise provided by law.

Such previously Existing Rights holders are New Participating TOs that have joined the CAISO and turned over the Operational Control of their facilities and Entitlements to the CAISO. Until December 31, 2010, such entities shall be entitled to receive the IFM Congestion Credit as provided in Section 11.2.1.5 of the CAISO Tariff. In the event that the rights are derived from an ETC with an Original Participating TO, the New Participating TO and the applicable Original PTO shall work together to submit the TRTC Instructions. (CAISO Tariff § 4.3.1.2.1)

CVRs are treated in the same manner with respect to scheduling, scheduling priority and settlement in the Day-Ahead Market. CVRs do not receive any special rights in the Real-Time Market in terms of scheduling priority or the reversal of Congestion Charges.

5.1.3 Non-Participating Transmission Owners

The transmission service rights and obligations of Non-Participating Transmission Owners ("Non-Participating TOs") under ETCs, including all terms, conditions and rates of the ETCs, as they may change from time to time in accordance with the terms and conditions of the ETCs, continue to be honored by CAISO and the parties to those contracts, for the duration of those contracts.

In addition, some Non-Participating TOs have Transmission Ownership Rights (TORs) that represent transmission capacity on facilities that are located within the CAISO Balancing Authority Area that are either wholly or partially own by the Non-Participating TO.

5.1.4 Transmission Ownership Rights

Transmission Ownership rights are rights that accrue either through ownership or joint-ownership of transmission facilities that are situated within the CAISO Balancing Authority Area but are not incorporated into the CAISO Controlled Grid because the Non-Participating Transmission Owners of such rights have not executed a Transmission Control Agreement.

In operating the DAM and the RTM CAISO accounts for the Transmission Ownership Right (TOR) capacity as follows:

- For TOR capacity on interties that are in the FNM, the CAISO reduces the available quantity scheduling rights at the intertie by the amount of the TOR.
- For TOR capacity that is internal to the CAISO Balancing Authority Area and modeled as part of the looped network, CAISO does not set aside capacity on the facility, but instead provides highest priority source-to-sink scheduling rights to the TOR holder. The source and sink points for such scheduling rights are determined by the TOR holder and

CAISO, consistent with the TOR holder's rights, in a manner that ensures the ability of the TOR holder to fully utilize its rights.

- TORs are not entitled to CRR payments, the balance of any CRR accounts or the Access Charges, but are settled under the "perfect hedge" in accordance with Sections 11.2.1.5 and 11.5.7 of the CAISO Tariff for transactions on their TOR systems.

In implementation and allocation of CRRs, the appropriate TOR capacity is removed from the FNM prior to running the CRR Allocation and CRR Auction markets by using Point-to-Point CRR Options. These Point-to-Point CRR Options will be held by the CAISO. Refer to Attachment B, section 4, of the BPM for CRRs for more information on this process.

TOR capacity reservations (i.e., the differences between TOR entitlements and TOR Self-Schedules) are made only on intertie. The CAISO will reserve unused TOR and make a corresponding adjustment in its determination of ATC (CAISO Tariff § 17.2)

The Non-Participating TO with a TOR works with the CAISO to develop any Transmission Rights and Transmission Curtailment (TRTC) Instructions required. The TRTC Instructions provided to CAISO to decide which Scheduling Point TOR has reservation requirements in which markets. Such instructions are part of the look-up tables or formulas for calculating the TOR. No TOR reservation is made in the DAM and RTM unless explicit instructions for reservation by markets are provided to CAISO.

5.1.5 TOR Scheduling Time Line Requirements

The TOR scheduling time line requirements specifies the latest time that an SC may submit TOR Self-Schedules and receive scheduling priority. Validation of the use of TORs is based on resource specific information. If a specific System Resource must be associated with certain TOR to be hedged from congestion, it is the responsibility of the Non-Participating TO to identify all possible sources and sinks eligible to utilize the TOR. The *BPM for Market Instruments* describes the scheduling process in more detail.

The following timeline applies to TOR Self-Schedules:

- In DAM, the SC must submit its TOR Self-Schedule by the close of the DAM (1000 hours) for its TOR. If the SC does not schedule all of its TOR, then transmission at an Intertie is reserved for the unused TOR amount in the RTM for that Intertie.

- In the RTM, the SC must submit TOR Self-Schedules by the close of the RTM (T-75 minutes) if the transmission right is for capacity on the transmission path at a Scheduling Point.

- In HASP, CAISO re-dispatches non-TOR or non-ETC resources to accommodate valid TOR Self-Schedule changes that are not at an Intertie in HASP provided the TRTC Instruction explicitly allows for such a scheduling right.

- In FMM, CAISO re-dispatches non-TOR or non-ETC resources to accommodate valid TOR Self-Schedule changes in Real-Time provided the TRTC Instruction explicitly allows for such a scheduling right.

- For TOR Self-Schedule changes between 75 minutes and 20 minutes prior to the Operating Hour, the relevant SC may schedule any remaining transmission rights by calling the CAISO Operator to input an Exceptional Dispatch in the RTM as appropriate (as described in CAISO Tariff Section 34.9). Intertie schedule adjustments (operating adjustments) are only allowed until T-20 minutes, except for System Emergencies and Forced Outages.

- The CAISO Real-Time Scheduler manually validates TOR Self-Schedule changes that occur after T-75. After assuring these changes are within the TOR and TTCs, the Real-Time Scheduler records the schedule change as TOR to properly settle the Schedule change.

- Once RTM is aware of the changes to the net interchange between Balancing Authority Areas in CAS, the changes are recorded as operational adjustments. To help the Real-Time Scheduler to validate the TOR Self-Schedule changes coming in after T-75, it is expected that the entire TOR Self-Schedule is re-submitted just as it should have been submitted before T-75 (i.e., if an hourly award is 100 MW at Palo Verde and the change at T-30 is an incremental addition of 30 MW, then the revised TOR Self-Schedule is 130 MW). By doing so, the CAISO Operator needs only to check that:

    - The TOR Self-Schedule submitted after T-75 must be not less than the TOR Self-Schedule submitted prior to T-75, if any;

    - The TOR Self-Schedule submitted after T-75 is not greater than the most current transmission right that can be queried from Existing Transmission Contract Calculator (ETCC); and

    - The TOR Self-Schedule changes are within the TTC.

5.1.6 TOR Scheduling Requirements

In the calculation of the Scheduling Point Transmission Interface Limits, the TOR Self-Schedules of the corresponding resources, as submitted by SCs (before being converted to the

regular Self-Schedules even if they are determined invalid by SIBR) are validated by SIBR and scheduled according to the following business rules:

- Only physical or System resources can exercise TOR scheduling priorities. The physical and System resources (including aggregations of physical resources) that are pre-specified as sinks or sources for the TOR can be scheduled by different SCs if they are associated with that TOR in the Master File. One physical resource can be a sink or source for multiple TORs.

- Several individual TORs can be bid back-to-back, i.e., the sink of one TOR can be the source for another TOR. TOR "chains" are treated as individual TORs, except that their validation is performed on each TOR sequentially (i.e. from the source to the sink using a contiguous path).[25] In such cases where a chain of Transmission Rights are linked a CRN representing the chain of rights will be established.

- If a TOR allows a single CNode to be used as both a sink and a source at different times but either a sink or a source at the same time, two CRNs must be created to implement the ownership right.

- Multi-point TORs are supported with multiple sources and multiple sinks. Each TOR may be associated with a list of Transmission interfaces, which may include interties. Unused TOR capacity will be reserved only on associated interties. TORs may be used in Wheeling transactions, which are limited from single import to a single export system resource.

- Source/Sink Resource IDs identify the resources, including aggregate resources that can be used to submit TOR Self-Schedule. Generating Units and import resources can be listed as sources, and Demand and export resources can be listed as sinks. Pumping Load, including Pumped-Storage Hydro Units, may be listed as sinks when they operate in the pumping mode. Multiple resources may be registered as sources or sinks for the same TOR. A resource may be listed as a source or a sink for many TORs. However, Pumped-Storage Hydro Units may not be listed as a source and a sink simultaneously for the same TOR. The source/sink Resource ID list may not be empty, even for a TOR that does not have a physical right. Resource associations are required even for Inter-

[25] The chain has to be either ETC or TOR, not a mix of both. However, if the chain is a mix of both ETC and TOR the CRN representing the chain will be assigned the ETC priority.

SC Trades at Aggregated Pricing Nodes because ISTs involving TORs are associated with physical resources as well as with transmission rights..

- Source/Sink Resource Maximum TOR capacity (MW). This is the maximum capacity that can be scheduled as a TOR from a resource that is listed as a source or a sink for that TOR.

- Source/sink Inter-SC trades at Aggregated Pricing Nodes Location identifiers. These identify the Locations (Price Nodes or Aggregated Pricing Nodes) that are associated with the source/sink resources for the purpose of honoring the applicable transmission right. These ISTs at Aggregated Pricing Nodes Locations may be the physical Locations where the relevant source/sink resources are connected in the Full Network Model (FNM), or different Locations if the Inter-SC trades at Aggregated Pricing Nodes are deployed differently from the physical right.

- Inter-SC Trades are not defined as resources that can be used as a source/sink for use of the TOR. However, the physical resource schedules behind a physical inter-SC Trade, not the inter-SC trade itself, can be use as the eligible source/sink for the purpose of validation of the use TOR.

While a number of SCs may use a TOR source/sink pair, a single SC must be designated as the SC for billing purposes for each TOR for Settlement purposes related to such TOR. The TRTC Instructions establishes all the sources and sinks allowed by the TOR.

The validation rules for TORs are described in more detail in Attachment A of BPM for Market Instruments.

5.1.7 ETC and CVR Scheduling Time Requirement

The ETC and CVR scheduling time requirements specifies the time frames in which a SC may submit ETC or CVR Self-Schedules pursuant to their Existing Rights or CVRs and receive scheduling priority afforded to ETC Self-Schedules as further discussed in the CAISO Tariff § 31.4 and 34.10 and according to the relevant provisions of the ETC and the exemption from Congestion Charges as further discussed in CAISO Tariff §§ 11.2.1.5, 11.5.7, 16.5, 16.6. Any specific scheduling time line requirements contained in the ETC must be explicitly included in the TRTC Instructions submitted to CAISO by the relevant PTO. (CAISO Tariff § 16.4)

The following timeline applies to ETC Self-Schedules and CVR Self-Schedules to the extent the scheduling time frame is permissible under the applicable ETC (CAISO Tariff §§ 16.5, 16.6 and 16.9). CVRs receive the same treatment as do Existing rights in the Day-Ahead Market but not in the Real-Time Market (CAISO Tariff § 4.3.1.2):

- In DAM, the SC must submit its ETC and CVR Self-Schedule by the close of the DAM (1000 hours) for its Existing Rights. If the SC does not schedule all of its Existing Right or Converted Rights, then transmission capacity is reserved for the unused ETC amount in the RTM for applicable Scheduling Point(s). Transmission capacity is not reserved for unscheduled amounts of ETC within the CAISO Balancing Authority Area. (CAISO Tariff § 16.5)

- In the RTM, the SC must submit ETC Self-Schedules by the close of the RTM (T-75 minutes) if the Existing Right is for capacity on the transmission path at a Scheduling Point. (CAISO Tariff § 16.9.1)

- In RTM, CAISO re-dispatches non-ETC or non-TOR resources to accommodate valid ETC Self-Schedule changes in Real-Time provided the TRTC Instruction explicitly allows for such a scheduling right and to the extent such flexibilities do not interfere or jeopardize the safe and reliable operation of the CAISO Controlled Grid or Balancing Authority Area operations. (CAISO Tariff § 16.10)

- For ETC Self-Schedule changes between 75 minutes and 20 minutes prior to the Operating Hour, the relevant SC may schedule any remaining Existing Rights by calling the CAISO Operator to input a ETC Self-Schedule change in the RTM as appropriate and permitted under the ETC and further reflected in the TRTC Instructions. Note that transmission capacity for unused Existing Rights is only reserved on transmission paths at Scheduling Points with other Balancing Authority Areas and no internal transmission facilities. Intertie schedule adjustments (operating adjustments) are only allowed until T-20 minutes, except for emergencies and Forced Outages.

- The CAISO Real-Time Scheduler manually validates ETC Self-Schedule changes that occur after T-75. After assuring these changes are within the Existing Rights and TTCs, the Real-Time Scheduler records the schedule change as ETC to properly settle the Schedule change. The CAISO accommodates these ETC Self-Schedules through an Exceptional Dispatch. (CAISO Tariff § 34.9.2).

- Once RTM is aware of the changes to the net interchange between Balancing Authority Areas in CAS, the changes are recorded as operational adjustments. To help the Real-Time Scheduler validate the ETC Self-Schedule changes coming in after T-75, it is expected that the entire ETC Self-Schedule is re-submitted just as it should have been submitted before T-75 (i.e., if an hourly award is 100 MW at Palo Verde and the change at T-30 is an incremental addition of 30 MW, then the revised ETC Self-Schedule is 130 MW). By doing so, the CAISO Operator needs only to check that:

- The ETC Self-Schedule submitted after T-75 is not less than the ETC Self-Schedule submitted prior to T-75, if any;
- The ETC Self-Schedule submitted after T-75 is not greater than the most current Existing Right that can be queried from ETCC; and
- The ETC Self-Schedule changes are within the TTC.

5.1.8 ETC and CVR Scheduling Requirements

ETC and CVR Self-Schedules as submitted by SCs are validated by SIBR to ensure consistency with the Existing Rights or CVR as reflected in the TRTC Instructions submitted for the applicable ETC or CVR using the following business rules. Also note that as per section 5.1.2 of market instruments BPM, Converted Rights (CVR) will be submitted into SIBR using the "Self Schedule ETC" Product Type (DAM only) and have the same priority as ETC.

- An ETC or CVR may have multiple injection (source) and withdrawal (sink) pairs, which are established by the TRTC Instructions.
- Only physical and System Resources (including aggregation of physical resources) can exercise ETC and CVR scheduling priorities. The physical resources that are pre-specified as eligible sinks or sources for the ETC in the TRTC can be scheduled. The physical and System Resources and sink may have different SCs that are responsible for scheduling the resources. Ultimately, the resources that are identified as eligible to use the ETC shall be stored in the Master-File and will be associated with the applicable Contract Reference Number for validation of the use of the ETC right when scheduling via SIBR. One physical resource can be a sink or source for multiple ETCs, TOR or CVRs. (See CAISO Tariff Section 16.4.5 and Section 17.1.4 for TORs.)
- Several individual ETCs or CVRs can be bid back-to-back. ETC or CVR "chains" are treated as individual ETCs or CVRs, except that their validation is performed on each ETC or CVR sequentially (i.e. from the source to the sink using a contiguous path). This is described in more detail in the *BPM for Market Instruments, Section 8*[26]. In such cases where a chain of Transmission Rights are linked a CRN representing the chain of rights will be established.

[26] The chain has to be either ETC or TOR, or a mix of both. However, if the chain is a mix of both ETC and TOR the CRN representing the chain will be assigned the ETC priority.

- If an ETC or CVR allows a single PNode to be used as both a sink and a source at different times but either a sink or a source at the same time, two CRNs must be created to implement the Existing Right.

- Multi-point ETCs are supported with multiple sources and multiple sinks. Each ETC may be associated with a list of Transmission interfaces, which may include interties. Unused ETC capacity will be reserved only on associated interties. ETCs may be used in Wheeling transactions, which are limited from single import to a single export system resource.

- Source/Sink Resource IDs identify the resources, including aggregate resources that can be used to submit ETC or CVR Self-Schedule ETCs. Generating Units and System Resources can be listed as sources, and Demand and export resources can be listed as sinks. Pumping Load, including Pumped-Storage Hydro Units, may be listed as sinks when they operate in pumping mode. Multiple resources may be registered as sources or sinks for the same ETC or CVR. A resource may be listed as a source or a sink for many ETCs or CVRs. However, for Pumped-Storage Hydro Units, a single resource may not be listed as a source and a sink simultaneously for the same ETC or CVR. This restriction does not apply to non- pump storage hydro units because such resources are either a source or a sink and not both. The source/sink Resource ID list may not be empty, even for an ETC or CVR that does not have a physical right. Resource associations are required even for Inter-SC Trades at Aggregated Pricing Nodes because ISTs involving ETCs or CVRs are associated with physical resources as well as with transmission rights.

- Source/sink resource maximum ETC or CVR capacity (MW). This is the maximum capacity that can be scheduled as an ETC or CVR from a resource that is listed as a source or a sink for that ETC or CVR.

- Inter-SC Trades are not defined as resources that can be used as a source/sink for use of the ETC or CVR. However, the physical resource schedules behind a physical inter-SC Trade, not the inter-SC trade itself, can be use as the eligible source/sink for the purpose of validation of the use ETC or CVR.

While a number of SCs may use an ETC or CVR source/sink pair, for every ETC or CVR there is a specific SC designated as the SC for Settlements purposes.

5.1.9 Scheduling Priority for Transmission Rights

In the event that there should be an in ability to clear the CAISO Market because all economic bids have been exhausted, ETC and CVR Self-Schedules are afforded a higher priority than

other Self-Schedules. The relative priority level globally for all ETCs and Converted Rights, because they may have different priority levels under the terms and conditions of their contracts, and all TORs which have the same priority level is as follows (CAISO Tariff § 31.4 and 34.10):

- TORs have the second highest scheduling priority in the CAISO Markets, after RMR type Generation Schedules that are needed for reliability. ETC and Converted Rights schedules have the third highest scheduling priority after RMR type and TORs.[27] ETCs and CVRs have the same scheduling priority.

SIBR will change the scheduling priority (and treats it like a regular Self-Schedule instead of ETC priority) to the entire ETC Self-Schedules, in the DAM only, if the total ETC Self-Schedules from the sources and the sinks are not balanced

SIBR will reject the ETC or TOR Self-Schedules and will not assign a Price-Taker priority if the ETC or TOR becomes invalid due to any of the following conditions (CAISO Tariff § 16.6):

- The ETC or TOR Self-Schedule is submitted with an incorrect Contract Reference Number
- The ETC or TOR Self-Schedule exceeds the resource capacity limit of the relevant ETC or TOR based on the TRTC Instructions
- The available capacity MWh limit in total exceed the non-zero available capacity MW limit permissible under relevant ETC or TOR.

5.1.10 ETC, CVR & TOR Settlement

The following summarizes the Settlement associated with ETCs and TORs:

- Both ETC and TOR Self-Schedules are not assessed the Access Charges and Congestion Charges for the balanced and valid portion of their ETC and TOR Self-Schedules. (CAISO Tariff § 16.6.3 and 17.3.3). CVRs are also not assessed Congestion Charges from the Day Ahead. (CAISO Tariff § 4.3.1.2) The Settlement mechanism

[27] Section 6.6.5.3, Scheduling Priorities, Section 7.5.3.2, RTM Self-Schedules and Section 7.5.3.3, Self-Schedules in HASP provide additional information on scheduling priorities.

reverses Congestion Charges in the same way for both TOR, CVR and ETC Self-Schedules.

- Unlike ETC Self-Schedules, TOR Self-Schedules also are exempt from UFE, Imbalance Energy offset, and neutrality charges. (CAISO Tariff § 17.3.3(3))

- ETC and CVR Self-Schedules are settled at Custom LAP (specific nodal) prices. Both are subject to Marginal Losses and the SCs submitting these ETC, CVR or TOR Self-Schedules receive refunds for the over collection of IFM Marginal Losses, based on system wide Marginal Loss revenue over-collection based on their Measured Demand. (CAISO Tariff § 11.2.1.6).

- ETC Self-Schedules are validated against the TRTC Instructions submitted by the PTO.

- TOR Self-Schedules are validated based on the TRTC Instructions developed by the Non-Participating TO with the CAISO.

- CVRs Self-Schedules in the Day Ahead are validated based on the TRTC Instructions submitted by the CVR holder and as appropriate with any applicable original PTO and were appropriate as provided in the CAISO Tariff § 4.3.1.2.1.

Additional details are provided in the Section 11 of the CAISO Tariff and *in the BPM for Settlements and Billing, Section 8*.

5.1.11 Transmission Rights & Curtailment Instructions (TRTC)

This section is based on CAISO Tariff § 16.4. Holders of Converted Rights, that are not associated with an Existing Contract must also submit TRTC Instructions for the Converted Rights as provided in CAISO Tariff § 4.3.1.2.1. In addition, holders of Transmission Ownership Rights (Non-Participating Transmission Owners) must also submit TRTC Instructions for their TORs (CAISO Tariff § 17.1.3)

Each PTO must work with the Existing Rights holders, to develop the TRTC Instructions. Holders of TORs must complete the TRTC Instructions for their applicable rights. New Participating TOs must complete the TRTC Instructions for the Converted Rights that they hold, that are not associated with an Existing Contract. In the event that Converted Rights are derived from ETCs that were converted involving an Original Participating Transmission Owner, the New Participating TO must develop the TRTC Instructions with the Original PTO. The TRTC Instructions must allow ETCs, Converted Rights and TORs to be exercised in a way that:

- Maintains the existing scheduling and curtailment priorities established in the ETC, Converted Rights, or if applicable TOR contract

- Is not unreasonably burdensome to CAISO (i.e., does not create an unreasonable impact on CAISO's preferred operational policies and procedures)

- Is consistent with the terms of the ETCs, Converted Rights or TORs and including preserving the operational characteristics of the ETCs or Converted Rights, while making as much transmission capacity not otherwise utilized by the holder of Existing Rights or Converted Rights as possible available to CAISO for allocation to Market Participants

- Is not unreasonably burdensome to the PTO, Non-Participating TO or New Participating TO and the Existing Rights holder from an operational point of view

- The TRTC Instructions should be provided in a clear enough fashion that does not require CAISO to engage in interpretation of the ETCs or Converted Rights to make assumptions about the economics of the deals struck in the contracts. These TRTC Instructions must be implementable without further interpretation by the CAISO.

The parties to ETCs attempt to jointly develop and agree on any TRTC Instructions that are submitted to CAISO. The parties to an ETC are also responsible to submit to CAISO any other necessary operating instructions based on their contract interpretations needed by CAISO to enable CAISO to perform its duties. If the holder of Existing Rights and the PTO disagree on the TRTC or operating instructions, CAISO implements TRTC or the operating instructions provided by the PTO in accordance with the CAISO Tariff.

In the calculation of Transmission Interface Limits, ETC reservations (i.e. the differences between ETC Encumbrances and ETC Self-Schedules) are considered only on Intertie Transmission Interfaces. The determination of the Limits for internal Transmission Interfaces used by the market software disregards ETC Encumbrances.

Transmission reservations at the interties for ETCs and CVRs are held in accordance with the Existing Rights or CVRs. The quantity of capacity consistent with the TRTC instructions is reserved for ETCs at the Interties. ETC capacity entitlements that are not associated with an Intertie are not reserved but are managed if necessary using redispatch. For CVR, unused CVR rights are available for use by others in the Day-Ahead Market, therefore the CVR rights are not reserved. The PTOs provide TRTC Instructions to CAISO to decide which Scheduling Point ETC has reservation requirements in which markets. Such instructions are part of the look-up tables or formulas for calculating the ETC Encumbrances. No ETC reservation is made

in the DAM and RTM unless explicit instructions for reservation by markets are provided to CAISO.

The TRTC Instructions identify the relevant Transmission Interfaces, also known as Transmission Interfaces, for ATC calculations and transmission capacity reservations. ATC calculation is performed for OASIS for each intertie and commercially significant paths, using the relevant TTC and ETC Encumbrances calculated by ETCC. Transmission capacity is reserved for unused Encumbrances by the market applications only on intertie Transmission Interfaces. If the Transmission Interface identifier is not unique and directional, a direction must also be specified.

Additional guidelines for completion and submission of the TRTC Instructions are posted on the CAISO website.

5.1.12 ETCs, CVRs and TORs Treatment in the Release of CRRs

The CAISO creates but does not release CRRs associated with expected use of ETCs and CVRs. CAISO models holders of Existing Right use of the CAISO Controlled Grid so the non-collection of the Congestion Charges does not create revenue inadequacy in the CRR allocation process. In its preparation of the Full Network Model for CRRs, the CAISO makes an adjustment to the available capacity for the TOR capacity identified through the TRTC Instructions. This is described in more detail in the BPM *for CRRs* and in Section 36.4 of the CAISO Tariff.

5.2 Available Transfer Capability Calculation

The purpose of calculating Available Transfer Capability (ATC) is for publication on OASIS. The following formulas are used to calculate ATC for all Transmission Interfaces including Scheduling Point Transmission Interfaces and internal Transmission Interfaces such as Path 15 and Path 26.

5.2.1 ATC Calculation before DAM Closes

Before DAM closes (i.e., before 1000 hours one day ahead) for the Trading Day, there are no ETC/TOR Schedule, net Energy Schedule, or AS Schedule on the Transmission Interface for the Trading Day. Therefore, the ATC for a Transmission Interface is calculated as follows.

Before DAM: ATC = Hourly TTC – CBM – Total Transmission Interface ETC Capacity – Total Transmission Interface TOR Capacity – TRM

Where:

Hourly TTC = Seasonal TTC – Constraint/derate caused by outages

Total Transmission Interface ETC/TOR Capacity = the sum of all the Capacity on the Transmission Interface.

Total Transmission Interface TOR = the sum of all the TORs on the Transmission Interface.

The ATC needs to be updated whenever TTC changes. TRM and CBM are at all times set at zero in the Day-Ahead Market.

5.2.2 ATC Calculation After DAM Completes & Before RTM Closes

After DAM completes and before RTM closes (i.e., after 1300 hours the day-ahead and before T-75 minutes of the Trading Hour), the ATC on each Transmission Interface for the Trading Hour is calculated as follows:

After DAM, for non-Intertie Transmission interfaces: ATC = Hourly TTC – CBM – TRM – Total Transmission Interface ETC Capacity – Total Transmission Interface TOR Capacity – DA net Energy Scheduled Flow

After DAM, for Interties: Import ATC = Import Hourly TTC – CBM – TRM – Total Import ETC Capacity – Total Import TOR Capacity – DA net Energy Scheduled Import – Total DA Regulation Up/ Spin/Non-Spin Import Awards

After DAM, for Interties: Export ATC = Export Hourly TTC – CBM – TRM – Total Export ETC Capacity – Total Export TOR Capacity – DA net Energy Scheduled Export – Total DA Regulation Down Import Awards

Where:

DA net Energy Scheduled Flow is the net DA scheduled Energy flow on the Transmission Interface in the relevant direction.

For each Transmission Interface in a specific direction, the Total Transmission Interface ETC Capacity is the sum of the expected DA ETC Schedule for the entire ETC on the Transmission Interface in the direction. For each Transmission Interface in a specific direction, the expected Total DA TOR Schedule is the sum of the expected DA TOR Schedule for all the TORs on the Transmission Interface in the direction. In the calculations set forth above, CBM is at all times

set at zero. For non-Intertie Transmission interfaces, TRM is also at all times set at zero. For Interties, TRM values are established in accordance with the procedures identified in section L.1.6 of Appendix L to the Tariff the ISO's NERC-mandated TRM Implementation Document.

5.2.3 ATC Calculation After RTM Completes

After RTM completes (after the Trading Hour), the Total ETC and TOR Reservation is zero, and the ATC calculation becomes the following:

After RTM: ATC = Hourly TTC – CBM – TRM – RT net Energy Scheduled Flow

Where:

RT net Energy Scheduled Flow is the total Real-Time Scheduled average energy flow on the Transmission Interface in the relevant direction during the Trading Hour.

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

Congestion Revenue Rights (CRRs) have no direct effect on the scheduling of Power in the CAISO Markets. However, the holders of CRRs are charged or credited for Congestion in DAM as described in the *BPM for Settlements & Billing*.

6.1.2 Full Network Model Build

One of the continuing CAISO processes is that of building and updating the FNM for power system operations and for the CAISO Markets. This process is described in more detail in the *BPM for Managing Full Network Model*.

6.1.3 Bid Information

Seven days before the Trading Day, the DAM is opened and ready to accept Virtual and physical Bid information from the SCs.

See the *BPM for Market Instruments* for more information.

6.1.4 Outage Information

Outage information may be submitted up to 12 months in advance of the Trading Day.

Three days before the Trading Day, the DAM (via the outage management system application) is ready to process Outage information for the DAM applications:

- Planned transmission Outage requests received 45 days in advance
- Review for possible adverse impacts on the CAISO Controlled Grid and CAISO Balancing Authority Area
- Planned Generating Unit Outage requests received 72 hours in advance for all types of units
- Review for possible adverse impacts on the CAISO Balancing Authority Area
- Approve or deny the requests.
- Outages over-ride Bids. If outage results in a more restrictive range in supplying Energy and providing Ancillary Services, the more restrictive range is used in market applications in performing Scheduling.
- Create the Outage schedule to be used by the market applications

For resources, outage information may be submitted for the following limitations:

- Resource is offline
- Resource is unable to provide Regulation
- Resource has more restrictive minimum and maximum operating limits than is recorded in the Master File.
- Resource has a different ramp rate than what was bid in.

6.1.5 CAISO Demand Forecast Information

Two days before the Trading Day, the DAM produces a CAISO Forecast of CAISO Demand via the Automated Demand Forecasting System (ALFS) application and publishes the forecast based on:

- Weather data
- Actual Load
- Historical information

CAISO produces a CAISO Forecast of CAISO Demand (CFCD) for each Trading Hour of the next three Trading Days to support the DAM, and a Load projection for each 15-min and five-min interval within the Time Horizon of the RTM applications. The CFCD is updated every half hour and is based on a regression of historical data and up-to-date weather forecast in terms of temperature information. The Demand projection is based on the CFCD and extrapolates actual Demand from the State Estimator solution using a neural network methodology. The CFCD is published on OASIS for each Demand Zone several days in advance and is updated regularly during Real-Time.

6.1.6 Determine Total Transfer Capability

Two days before the Trading Day the CAISO determines the TTCs of the transmission interfaces and publishes that information by 1800 hours at the OASIS.

6.1.7 Before Day-Ahead Market is Closed

The following activities are performed one day before the Trading Day before the DAM closes:

- By 0530 hours, the CAISO compiles Eligible Intermittent Resource (EIR) data based on a seven-day true wind forecast.
- By 0830 hours, the CAISO updates and publishes the available ETC capacities.
- By 0830 hours, the CAISO determines and publishes the ATCs.

Since a lot of transactions outside of CAISO Balancing Authority Area take place by 0500 hours, if there are changes to TTC after 0500 hours, CAISO needs to coordinate with other Balancing Authority Areas and communicates updates if they occur.

Generally, CAISO can make changes that result in an impact to the CAISO markets due to a change in outage conditions up to 0800 hours in coordination with other Balancing Authority Areas (BAA), and provide information back to Market Participants. If there is a change in TTC by that time that results in a reduction in ETC rights, any ETC Self- Schedules that have been submitted are revalidated at that time and the SC scheduling such ETC is informed of any violations. If there is an increase in TTC, the changes will only increase the feasibility of submitted schedules. In either case, CAISO makes updates to Market Participants, if needed. If the changes to the market systems due to a change in an outage in the CAISO Controlled Grid are submitted after 0800 hours, they will only be entered into market systems on an exception basis and only if all of the following can be completed before 0900 hours:

- they can be fully coordinated with other affected Transmission Operators and BAAs, and
- entered into all systems affected by the change.

CAISO publishes based on known network conditions, e.g., knows that a line is down, and incorporates that information. Also, temperature forecasts, which lead to derating a line, are also included when data is published. Details of reports provided by CAISO are shown in *BPM for Market Instruments*, Section 13.

TTC/ATC continues to be published seven days in advance. The following is published on OASIS:

- Transmission Interface capacities
- Load forecast
- Expected flow
- Scheduled derates

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 BAA Demand. 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 BAA Demand, and to the extent that Virtual Supply has displaced physical Supply, RUC may need to commit more physical resources and/or more Reliability Capacity (RCU) in order to make sure that there is enough physical capacity covering the CAISO Forecast of BAA 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.

6.1.9 IFM Initial Conditions

A Generating Unit that was committed in the previous day's Day-Ahead Market (IFM or RUC) run (TD-2 for TD-1) but was de-committed before HE24 would normally be considered initially offline in the next day's IFM run for the Trading Day (TD). However, in the event that the Scheduling Coordinator for such Generating Units have submitted Self-Schedules in the Real-Time Market for the remaining hours of the day in which it was not committed in the Day-Ahead Market for the TD-1 date, the CAISO may assume that the Generating Unit is indicating its intent to be on line at the beginning of the next day (TD). In that case, the CAISO market operator may set the initial condition for such a resource in the IFM conducted on TD-1 for the TD to be online taking into consideration the following conditions:

- The unit was offered in the Day-Ahead Market for all hours through hour ending 24 where it was not economically committed by the IFM from the previous day (TD-1)
- The unit is economically committed for some hours of the TD-2 for TD-1 IFM or RUC processes, but is not committed through the end of TD-1. An IFM partial day self-schedule commitment will not trigger this criterion.
- By one hour prior to the close of the Day-Ahead Market for TD (i.e. at 09:00 on TD-1), the unit has Self-Scheduled Energy (presumably, but not necessarily at PMin) in the RTM for TD-1 for each of the remaining hours after the last economically-committed hour in the DAM for TD-1.
- No risk of an over-generation condition is anticipated for any hours in TD-1.

In addition, the CAISO monitors the interaction of the initial condition setting and Self-Schedule behavior by Scheduling Coordinators. For example, If the CAISO observes that a Scheduling Coordinator tends to withdraw its Self-Schedules after the close of the Day-Ahead Market, but prior to the close of Real-Time Market, the CAISO can consider such behavior and inform its decisions in setting the initial conditions for the next day's IFM.

The initial condition of the resource consists of the resource's status, operating level, and for Multi-Stage Generating Resources, the operating MSG Configuration. When the operator, following this process, adjusts a resource's initial condition, they will adjust the operating level and MSG Configuration as follows:

- Non- Multi-Stage Generating Resource – the operating level will be set to the resource's Minimum Load
- Multi-Stage Generating Resource – the MSG Configuration will be set to the lower of a) the configuration in the last hour of the IFM commitment for TD-1; and b) the self-scheduled configuration in the Real-Time Bid for Hour Ending 24 on TD-1. The operating level will be set to the Minimum Load of the selected MSG Configuration.

The initial condition will be set to the Minimum Load of the unit / MSG Configuration even if the RTM Self-Schedule is higher than Minimum Load. If the SC only offered the unit to be self-scheduled in the IFM run on TD-2 for TD-1, then the unit will not be a candidate for its initial condition to be set as online for the IFM run for the TD run on TD-1. The CAISO monitors how the Generating Units Self-Schedule their resources to inform the decisions the operators make in setting the initial conditions based on their self-scheduling practices.

On any given day that the CAISO does not consider the next day's Self-Schedules in setting initial conditions, the CAISO will notify Scheduling Coordinators via the OASIS system operating messages. Furthermore, the setting of a resource's initial conditions does not supersede the scheduling of resources in IFM through the security constrained economic dispatch and unit commitment process of the IFM for a given Trading Day and only serves as an input to the IFM to inform operators on setting the resource's initial conditions to facilitate a more efficient operation of the market and grid.

In setting the initial conditions in the Day-Ahead Market for TD the ISO operator or systems may also consider a resource's actual status (on-line or off-line) and on time (how long the resource has been in its current status) at the time of the close of the market (1000 TD-1). If a resource that does not have a Day-Ahead Market schedule for the previous and current hours of the current day in which the Day-Ahead Market is run is actually online at the time of the close of the Day-Ahead Market for TD (1000 TD-1), and in addition has a Day-Ahead Market schedule for a future hour of the current day including hour ending 24 of the current day, then an assessment of the resources ability to actually cycle off and back on prior to its upcoming schedule of the day may occur. If the ISO operator or systems determine that the resource would be unable to cycle off and back on without violating the resources registered minimum down time, then the resources on time will reflect its actual time on, as of the close of the market, plus the remaining hours of the current day. If an MSG resource's initial conditions is in a configuration that cannot be shut down or transitioned and the MSG resource has an outage

for the Day-Ahead Market TD, the ISO operator may set the initial conditions of the MSG resource or configuration to off-line.

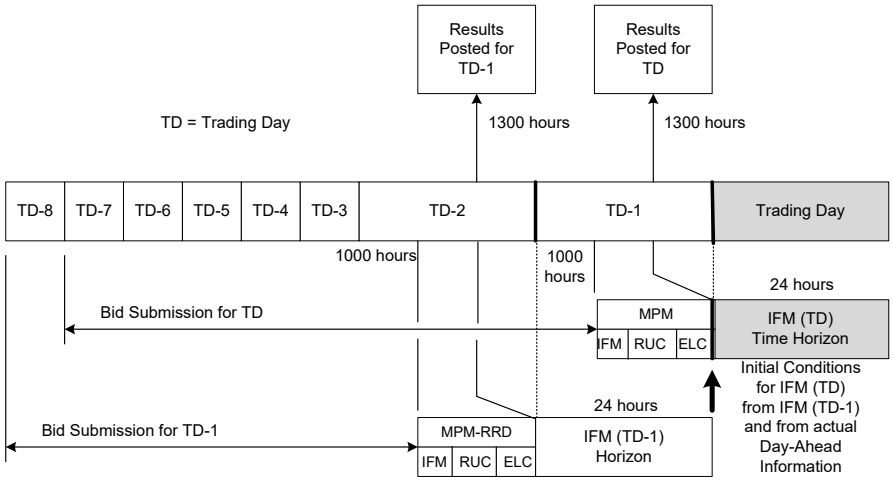
Initial Conditions and Self Scheduling in EDAM

The Initial Condition for each generating resource shall reflect the status indicated in the Scheduling Coordinator's HE1 self schedule submitted prior to the binding Day Ahead market run for the next operating day. Scheduling Coordinators may submit a Day Ahead HE1 self schedule specifying whether the resource is expected to be online or offline, along with any anticipated MSG configuration changes, whether increases or decreases. Scheduling Coordinators are responsible for ensuring that all submitted self schedules are feasible, including compliance with minimum run time requirements and any applicable outages. Initial Condition updates begin before the 06:00 Advisory RSE run and are refreshed in each subsequent RSE advisory run, as well as prior to the 10:00 Binding RSE run and the subsequent market execution. If a Scheduling Coordinator submits both a Day Ahead HE1 self schedule and a Real Time self schedule through the self bridging process, and the two differ, the Real Time self bridge schedule prevails. See EDAM BPM for further detail.

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). 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 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
- 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

Reliability Capacity (RCU/RCD) is not tagged. Energy associated with a 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 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 final Reliability 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.

6.3.3 Respond to Day-Ahead Market Published Schedules & Awards

It is the responsibility of SCs to respond to CAISO published Schedules and Awards starting up units and achieving specified operating levels in a timely manner. SCs are also financially responsible for awarded Bids and Self-Schedules into the CAISO Markets.

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

CAISO accepts DAM inputs from the following principal sources:

- SIBR
- Master File
- ETCC
- outage management system/ALFS

6.4.2 Disseminate Pre-Market Information

The following information is published in support of the DAM:

- Public Transmission information in OASIS:
  - Future planned Outages of transmission facilities
  - Operational Transfer Capability and Available Transfer Capability on Transmission Interfaces including WECC paths and interconnections with external Balancing Authority Areas.

- Demand forecast public information in OASIS:
  - Beginning seven days prior to the Trading Day, and updated as necessary, CAISO publishes its peak CAISO Demand forecasts by IOU service territory.
  - By 1800 hours the day prior to (two days before the Operating Day) the target DAM, CAISO publishes its updated CAISO Demand forecast by IOU service territory.

- Network and system conditions public information in OASIS[28]:
  - By 1800 hours two days ahead of the Trading Day, CAISO publishes known network and system conditions, including but not limited to TTC and ATC, the total capacity of Inter-Balancing Authority Area Interfaces, and the available capacity.

- Ancillary Services requirements public information in OASIS:
  - By 1800 hours two days ahead of the Trading Day, CAISO publishes forecasted AS requirements and regional constraints by AS Region. A minimum and/or maximum constraint, expressed as hourly MW, is given for each AS Region. For AS Regions where no limit is applicable, the CAISO publishes a 0 MW minimum and/or an appropriately large maximum.

- Relevant Gas Price Indexes public information in OASIS when available. Refer to the *BPM for Market Instruments, Attachment C* for details.

- SIBR sends messages to SCs regarding the status of their Bid validation continuously as Bids are submitted until the DAM is closed at 1000 hours.

[28] CAISO understands the MPs' desire for market related information. However, there may be limitations on the publication of data for non-competitive constraints due to market sensitivity, power system security and the confidentiality of data provided to CAISO by MPs.

- SIBR sends messages to SCs regarding the status of their trade validation continuously as trades are submitted and for physical trade pre-market validation, every 20 minutes between 6:00 am and the close of the trade market 11:00 am.

6.4.3 Disseminate Post Market Close Information

The following information is published in support of the DAM following Market Close:

- After the close of the DAM bidding at 1000 hours, CAISO sends a message to the SCs regarding the final outcome of the Bid validation.

- By 1300 hours, CAISO publishes the result of the DAM and the resource is flagged if it is being Dispatched under its RMR Contract. Any such Dispatch is deemed a Dispatch Notice under the RMR Contract.

6.4.4 Procedures for Closing the Day-Ahead Market

Bidding for DAM is closed at 1000 hours on the day preceding the Trading Day.

Consistent with Sections 7.6 and 7.7 of the CAISO tariff, the following actions are taken in the event of market disruptions. Actions taken vary depending on the cause of failure, expected time of resolution, and the status of the submitted Bids at the point of failure:

- Postpone the closure of the market. Postponement may be accommodated for a maximum of approximately two hours without impacting scheduling and Balancing Authority Area check out processes.

- Closing of the market and manual copying of Bids or Schedules from previous Trading Day.

- Closing of the market and using submitted Bids to the extent possible. Note, CAISO recommends that Scheduling Coordinators have seven days of Bids submitted to SIBR as a default in case Bids are not able to be submitted for a particular Trading Day.

- Cancellation of the market with import/export schedules being determined by submittal of an E-Tag. Established WECC scheduling rules apply when a failure of an E-Tag occurs when submitting interchange transactions

- Suspension of all Virtual Bids at specific Eligible Pnodes or all Eligible Pnodes to allow all physical Bids to be cleared.

- If cancellation of the market or suspension of all Virtual Bids occurs, CAISO may issue operating orders for resources to be committed and dispatched to meet Demand. In this case, CAISO will set administrative prices to be used for settling Metered Supply and Demand as reflected in Section 7.7 of the CAISO Tariff.

Validation for Bids at Transmission Paths with Zero Rated TTC in Both Directions

As further discussed in the BPM for Market Instruments, the ISO market systems will validate all Bids, including Self-Schedules and Virtual Bids, for each Trading Hour to ensure that Bids submitted at open ties (i.e., interties where the transmission path TTC is rated to zero in both directions) are not considered in the ISO market processes, as required by Section 30.8 of the ISO Tariff. However, bids for System Resources which have registered an alternate tie path in the Master File will be considered in the IFM to be bid at the alternate path if the primary tie path is open. For these resources, if both the primary and alternate path is open, only then will the bid not be considered in the ISO market processes.

No Bids at Transmission Paths with Zero Available Transmission Capacity (ATC)

With the exception of transmission rights holders, the ISO will not accept Bids, including Self-Schedules and Virtual Bids, at an intertie Scheduling Point that is fully encumbered by transmission rights holders where the ATC is set to 0 MW.

6.4.5 Execute Day-Ahead Market Applications

The following Day-Ahead applications are executed by CAISO after the Market Closes:

- MPM
- IFM
- RUC

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[29]:

- **Day-Ahead Generation Market Results** – Schedules of all generating resources.

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

- **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 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 Instruction**s – Commitment instructions of all resources from the DAM.

- **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[30].

Exhibit 6-2: Generating Unit Commitment Selection by Application

Attribute	Short Start	Long Start	Extremely Long-Start
Start Up Time / Cycle time[31]	**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[32]	**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.

[30] 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.

[31] 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.

[32] Extremely Long Start Commitment Process

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 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 BAA Demand in DAM is hourly.
  - The Energy Bid and Imbalance Reserve Up 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[33] 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

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

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). The MPM process consists of a single market optimization run in which all modeled transmission constraints are enforced in the base scenario, and a configurable set of those transmission constraints is enforced in the imbalance reserve up deployment scenario, and the imbalance reserve down deployment scenario. The specific transmission constraints enforced in the deployment scenarios are identified in the Flexible Ramping Product Market Design section**Error! Reference source not found.**. The binding transmission constraints in these scenarios are evaluated for competitiveness using the Dynamic Competitive Path Assessment (DCPA) process, which is discussed in further detail in Section 6.5.3.

After the market optimization, each nodal price in the market is decomposed into: (1) the system marginal component; (2) the loss component (for energy only); (3) the competitive congestion component; and (4) the non-competitive congestion component.

For energy (LMP) at location i:

$$LMP_i = EC_i + LC_i + CC_i^{Base} + CC_i^{IRU} + CC_i^{IRD} + NC_i^{Base} + NC_i^{IRU} + NC_i^{IRD}$$

For Imbalance Reserve Up (IRUMP) at location i:

$$IRUMP_i = SysIRU_t + CC_i^{IRU} + NC_i^{IRU}$$

For Imbalance Reserve Down (IRDMP) at location i:

$$IRDMP_i = SysIRD_t + CC_i^{IRD} + NC_i^{IRD}$$

where

- EC stands for the energy component,
- LC stands for the loss component,

- SysIRU and SysIRD stand for the system marginal reserve shadow prices for IRU and IRD, respectively.
- CC_i^{Base} and NC_i^{Base} stand for the competitive and non-competitive congestion contributions from the base scenario.
- CC_i^{IRU} and NC_i^{IRU} stand for the competitive and non-competitive congestion contributions from the IRU deployment scenario.
- CC_i^{IRD} and NC_i^{IRD} stand for the competitive and non-competitive congestion contributions from the IRD deployment scenario.

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.

- 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 sum of the non-competitive congestion components from all three scenarios ($NC_i^{Base} + NC_i^{IRU} + NC_i^{IRD}$).
- 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 (NC_i^{IRU}).

Imbalance Reserve Down (IRD) Bids: IRD bids are not subject to market power mitigation. 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.

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.

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, virtual energy schedules, 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 and virtual energy schedules.
- In the upward deployment scenario, the demand for counter-flow considers the combined flow from both the physical and virtual energy schedules and the Imbalance Reserve Up (IRU) award.
- In the downward deployment scenario, the demand for counter-flow considers the flow from the physical and virtual energy schedules 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 Bid Adder for Frequently Mitigated Units

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 reference point for IRU bids across all resources and market intervals. The initial default value is set to $55/MWh. 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. 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 Mitigation Exemptions for Small Storage Resources

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

6.5.6.1 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 **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[34].

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. The IFM procures Ancillary Services[35] 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 BAA 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.

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

[35] "Unless otherwise specified, references in this BPM to procurement of Ancillary Services refer to procurement for the CAISO Balancing Authority Area. For non-CAISO EDAM BAAs, Ancillary Service requirements are self-provided and not co-optimized in the IFM.

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, AS Awards, and Imbalance Reserve Awards, and their related LMPs and 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 capacity 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, 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, a storage resource is able to withdraw energy from the grid to charge, and hasve a limited energy storage capacity. The lower operating ~~range~~ minimum 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~~envelope constraints and the ancillary service state of charge constraints as outlined below 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, all DA market runs ~~the IFM~~ enforce~~s~~ State of Charge (SOC) constraints for storage resources. These constraints ensure a resource has sufficient energy to provide its awarded services.

Ancillary Service State of Charge (ASSOC) Constraint

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). The mathematical formulations for the ASSOC constraints are:

$$SOC_{i,t-1} - RU_{i,t} - SR_{i,t} - NR_{i,t} - IRU_{i,t} \geq \underline{SOC_{i,t}}$$

$$SOC_{i,t-1} + \eta_i\left(RD_{i,t} + IRD_{i,t}\right) \leq \overline{SOC_{i,t}}$$

$$SOC_{i,t-1} - RU_{i,t} - SR_{i,t} - NR_{i,t} - IRU_{i,t} \geq \underline{SOC}_{i,t}$$

$$SOC_{i,t-1} + \eta_i(RD_{i,t} + IRD_{i,t} \leq \overline{SOC}_{i,t}$$

Where:

- $SOC_{i,t-1}$ is the state of charge at the end of the previous hour.
- η_i is the charging efficiency.
- $\underline{SOC}_{i,t}$ and $\overline{SOC}_{i,t}$ are the minimum and maximum state of charge limits.

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 and configurable attenuation factors. 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.

The mathematical formulations for the SOC envelope constraints in IFM are:

$$SOC_{i,t}^{(u)} = SOC_{i,t-1}^{(u)} - EN_{i,t}^{(+)} - \eta_i EN_{i,t}^{(-)} + \eta_i AIRD_t IRD_{i,t} \leq \overline{SOC}_{i,t}$$

$$SOC_{i,t}^{(l)} = SOC_{i,t-1}^{(l)} - EN_{i,t}^{(+)} - \eta_i EN_{i,t}^{(-)} + AIRU_t IRU_{i,t} \leq \underline{SOC}_{i,t}$$

$$\left.\begin{aligned} SOC_{i,t}^{(u)} &= \left(SOC_{i,t-1}^{(u)} - EN_{i,t}^{(+)} - \eta_i EN_{i,t}^{(-)} - ARU_t RU_{i,t} - AIRU_t IRU_{i,t}\right) \geq \underline{SOC}_{i,t} \\ SOC_{i,t}^{(d)} &= SOC_{i,t-1}^{(d)} - EN_{i,t}^{(+)} - \eta_i \left(EN_{i,t}^{(-)} - ARD_t RD_{i,t} - AIRD_t IRD_{i,t}\right) \leq \overline{SOC}_{i,t} \end{aligned}\right\}$$

The parameters $AIRU_t$ and $AIRD_t$ are configurable attenuation factors (multipliers) attached to the imbalance reserve awards. The current values for these factors are maintained in the BPM section on configurable parameters.

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 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, AS, and Imbalance Reserves. The IFM utilizes this capacity for the most economically efficient combination of Energy and AS.

Like AS, Imbalance Reserves awards do not create net counterflow against energy schedules 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.

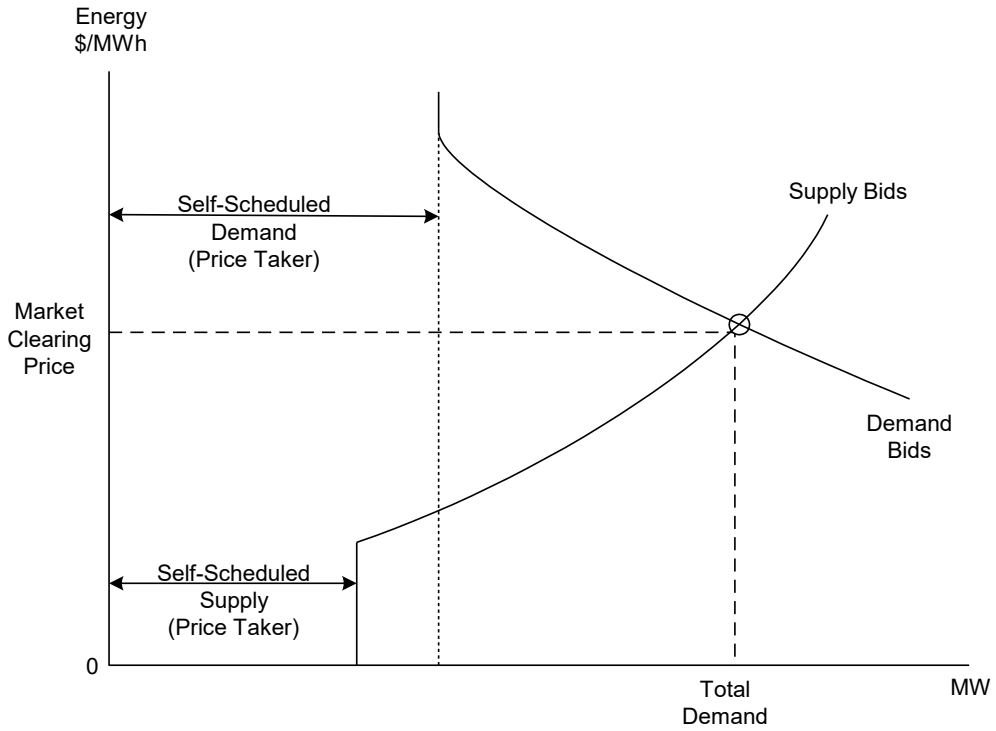
6.6.4 Market Clearing

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[36] 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 balance	4900	1000	9800	2000	Market energy balance is the 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

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

Penalty Price Description	Scheduling Run Value[36] 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
					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 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

Penalty Price Description	Scheduling Run Value[36] 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
					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 Regulation-up and Regulation-down Minimum Requirements	2500	250	5000	250	In the event of bid insufficiency, AS minimum requirements will be met 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.

Penalty Price Description	Scheduling Run Value[36] 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
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 CAISO demand and self-scheduled exports using identified non-RA capacity. Export leg of wheel through self-schedules	1800	1000	3600	2000	Pursuant to section 31.4, the 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,	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.

Penalty Price Description	Scheduling Run Value[36] 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
Exports leg of a low priority wheel through self-schedule					
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	-8100	NA	-12200	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	-6050	NA	-12100	NA	Conversion of AS self-schedules to Energy pursuant to section 31.3.1.3 receives higher priority to maintaining the availability of spinning reserve, over non-spinning reserve.
Conditionally qualified Non-Spin self-provision	-6000	NA	-12000	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.

Penalty Price Description	Scheduling Run Value[36] 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
Conditionally unqualified Reg Up or Down self-provision	-195	NA	-390	NA	In instances where AS self-provision is not qualified pursuant to the 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.
Open access transmission tariff	5050	1000	10100	2000	OATT transmission service rights under EDAM entity and EDAM transmission provider OATT.
Green house gas net import allocation	6500	1000	13000	2000	Penalty price for green house gas (GHG) net import allocation constraint. Market optimization will not allow net import into a GHG area more than GHG attribution.

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.

Penalty Price Description	Scheduling Run Value	Pricing Run Value	Comment
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. 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. 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	259	250	Market energy balance when the RUC procurement may be more than the Demand forecast.
Price-taker IFM cleared supply self-schedules. IFM cleared import leg of a wheel through self-schedule	-1350	0	IFM cleared price-taker supply bids and IFM cleared import leg of a wheel through self-schedule

Penalty Price Description	Scheduling Run Value	Pricing Run Value	Comment
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 scheduling	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 run parameter reflects energy supply shortage.
Gas-burn	1500	1000	3000	2000	Scheduling run penalty price will

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
nomogram					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 parameter for all energy supply self-schedules.

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
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. Energy bid floor is the pricing parameter for all energy supply

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
					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 (RTUC only)	-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
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 constraint relaxation. The scheduling run parameter is

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
					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
Exceptional Dispatch	5800	1000	11600	2000	Priority to exceptional dispatches made by operators

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
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 RUC schedule	0.0001	0	0.0002	0	Import side of a low priority wheel self-schedule

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
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.
Open access transmission tariff	5050	1000	10100	2000	OATT transmission service rights under EDAM entity and EDAM transmission provider OATT.
Green house gas net import allocation	6500	1000	13000	2000	Penalty price for green house gas (GHG) net import allocation constraint. Market optimization will not allow net import into a GHG area more than GHG attribution.

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.

DAME Configurable Parameters

Five key parameters outside of other market processes inform the ISO's procurement of imbalance reserves and/or reliability capacity. These are:

1. Transmission constraints enforced in imbalance reserves deployment scenarios
2. Proportion of deliverable imbalance reserves in deployment scenarios
3. Imbalance reserve demand curve cap
4. Default availability prices for mitigation of imbalance reserves up and reliability capacity up products
5. Envelope constraint multipliers for storage resources

The following outlines these values effective as of May 1, 2026 with initial procurement of the imbalance reserves and reliability capacity products. As the ISO gains operational experience and more data becomes available, it will continue to evaluate these parameters and adjust their values as appropriate. The ISO will provide transparency regarding this ongoing evaluation, and any proposed adjustments will be considered through an open and transparent process, engaging market participants in discussions about any proposed changes.

1) Set of transmission constraints

This parameter defines which transmission constraints are enforced in deployment scenarios for procuring imbalance reserves. In ISO markets, there are three types of transmission constraints: base flowgates, contingency flowgates, and nomograms. This framework provides flexibility to determine which constraints are enforced, considering optimization performance, market

performance, and operational experience. The day-ahead market will enforce base flowgates and nomograms for the imbalance reserve deployment scenarios

2) Proportion of deployed imbalance reserves

This parameter defines the proportion of imbalance reserve awards that will be assessed for deliverability against the transmission constraints enforced in deployment scenarios. These scenarios evaluate imbalance reserves to ensure that the specified share, determined by this parameter, can be successfully deployed without violating transmission constraints. This parameter is set to 45%

3) Imbalance reserve demand curve cap and 4) Default availability prices for IRU/RCU mitigation

The cap defines the maximum bid eligible for imbalance reserves, as well as the maximum price used to construct the demand curve. The default availability price serves as the reference price for market power mitigation for both imbalance reserves and reliability capacity upward. Both parameters are set at $55/MW, as specified in the tariff.

5) Envelope constraint multipliers

For storage resources, the day-ahead market will establish upper and lower bounds, i.e., an "envelope" for state of charge, which may constrain resource operations. This parameter, also referred to as the envelope constraint multiplier, determines the proportion of energy that must be available in the state of charge to support an imbalance reserve award. This multiplier is set at 45% in the IFM process.

A similar envelope constrains concept and multiplier apply in the RUC process for reliability capacity awards. Unlike imbalance reserves, where realized uncertainty can vary, and therefore the proportion of state of charge needed to support deployment may also vary, reliability capacity upward awards are intended to meet a specific level of the day-ahead load forecast. As a result, it is necessary to ensure that sufficient state of charge is available to fully support these awards. Accordingly, this multiplier is set at 100% in the RUC process.

In addition to the five formal parameters within the scope of the day-ahead market enhancement functionality, the ISO also considered the level of imbalance reserve requirements used in both the resource sufficiency evaluation and the day-ahead market. The imbalance reserve requirements are set at the 90th percentile for upward reserves and the 10th percentile for downward reserves for use in both the day-ahead resource sufficiency evaluation and the day-ahead integrated forward market.

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 within a BAA. The shadow price BAA's individual of the power balance constraint establishes the BAA marginal energy cost, (MEC) which the market uses to determine locational marginal prices for that BAA. 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)[37]	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.[38] 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
- Optimal Imbalance Reserve (IRU/IRD) Award for all eligible resources over the Time Horizon
- Virtual Supply and Virtual Demand Awards
- Optimal AS Award for all resources over the Time Horizon
- The total Energy, 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 Balancing Authority Area (BAA) specific requirements.

To account for the geographical spread of the EDAM footprint, the CAISO calculates a "diversity benefit." This benefit recognizes that net load uncertainty is unlikely to materialize at extreme levels across all BAAs simultaneously. The individual BAA requirements are first calculated based on local historical forecast errors and then reduced proportionally by the diversity benefit to ensure the total procurement reflects the requirements of the integrated footprint.

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 amount of awarded reserves tested for

deliverability is controlled by a configurable "Deployment Factor." The Deployment Factor determines the percentage of that award that must be feasible against transmission limits.

During these scenarios, the IRU/IRD requirements are distributed to the individual nodes within the BAA to balance the awards. This distribution is performed by superimposing the uncertainty requirement onto load nodes and Variable Energy Resource (VER) nodes using load, solar, and wind allocation factors derived from historical data.

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 BAA-level requirement for IRU and IRD, which is determined based on historical forecast errors and adjusted to reflect the diversity benefit of the EDAM footprint.
- An Imbalance Reserve Demand Curve is used for each BAA to relax the procurement requirement at high prices, assessing the trade-off between the procurement cost and the operational value of the reserves. The demand curve is a monotonically decreasing stepwise curve with segments based on a $247/MWh avoidance cost. However, demand curve values are capped to $55/MWh for both IRU and IRD.
- 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 will calculate the IRU and IRD requirement for each hour of the Trading Day for each BAA in the EDAM area and for the entire EDAM area. This calculation is based on the historical uncertainty in the 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 demand, wind, and solar for the upcoming Trading Day. This statistical method estimates the requirement needed to cover a target percentile of expected forecast error (e.g., 90% for upward need and 10% for downward need)..

EDAM entities will have the following threshold information via OASIS (see below) the prior day to help guide them on the uncertainty requirements, but these requirements will update during the day with updated forecast information:

- Dynamic Threshold
  Energy → Imbalance Reserve → Imbalance Reserve Requirement Thresholds
  (Percentile: LOW, Data Type: Histogram)
- Static Threshold
  Energy → Imbalance Reserve → Imbalance Reserve Requirement Thresholds
  (Percentile: HIGH, Data Type: Mosaic)
- Floor Threshold
  Energy → Imbalance Reserve → Imbalance Reserve Requirement Thresholds
  (Data Type: Histogram)

For more information on the calculation of Imbalance Reserve Requirement see Appendix O

Demand curve for imbalance reserves

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 price value that serves as the mitigation reference point for RCU bids. This value is set to be the same price as the Default Availability Bid for Imbalance Reserve Up.

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 BAA 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 BAA Demand, and to ensure that sufficient physical reliability capacity is committed or otherwise available for Dispatch in Real-Time in order to meet the Demand Forecast for each Trading Hour of the Trading Day. This assessment and procurement are performed for each BAA within the EDAM footrprint. 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 reliability capacity (RCU/RCD) from resources that are committed and scheduled in the IFM.

The RUC process procures capacity for the 24-hour day-ahead time horizon.

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 BAA Demand (here after CFBD) 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 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 Reliability Capacity Bids instead. 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, locational marginal prices for RCU and RCD. The RUC process thus designates 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 CFBD on Full Network Model
- Day-Ahead Schedules for Supply
- Reliability Capacity (RCU/RCD) Bids
- RUC Operational Constraints
- RUC Execution
- RUC Outputs

6.8.1 RUC Objective

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

- Incremental costs are represented by the bids for Reliability Capacity Up (RCU) and Reliability Capacity Down (RCD).. Resources receive payment for awarded reliability capacity at the relevant locational marginal price.

- 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 Reliability Capacity necessary to meet the adjusted CFBD.

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.

6.8.2.1 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 Reliability Capacity Awards (RCU/RCD))

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, and 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 CFBD on a local area basis as input to the RUC process, to ensure that the RUC process results in adequate local capacity procurement. The CFBD 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.

RUC Zones are currently defined only for the CAISO BAA. For other BAAs in the EDAM footprint, RUC procurement and RUC adjustments are performed at the BAA level. The CAISO does not initially define granular RUC Zones for non-CAISO BAAs.

The CAISO will initially use three RUC Zones corresponding to three TAC areas within the CAISO BAA. For other EDAM BAAs, a RUC Zone will typically correspond to the BAA's footprint. The number of RUC Zones may increase in the future in order to adjust the CFBD 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.

6.8.2.3 CAISO Forecast of BAA Demand (CFBD)

CFBD 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 CFBD serves as the RUC procurement target; the difference between the CFBD and the physical supply schedules from the IFM determines the need for upward or downward reliability capacity within each RUC Zone.

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 demand forecasting results to ensure the average forecast error is minimized.

6.8.2.4 RUC Procurement Target

The RUC procurement target is based on the difference between CFBD and the physical supply cleared in the IFM for each Trading Hour of the next Trading Day within each RUC Zone, and based on the CFBD 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 for that RUC Zone.

The CFBD 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 are modeled as fixed schedules with high scheduling priority so that RUC identifies the incremental RCU or RCD needed to serve the difference between the physical supply and the adjusted CFBD.

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, CFBD is lowered accordingly which in effect reduces the RUC procurement target.

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, an EDAM entity may consider the following adjustments to the hourly CFBD by RUC zone. After all the individual adjustments are determined as described below the CAISO based on the information provide by EDAM entities will adjust the CFBD of each affected RUC zone, without making changes to the LDFs within that RUC Zone. The RUC Zone CFBD adjustment can be absolute or relative as follows:

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

Or

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

Where:

- $\Delta CFBD_{RZ,hour,adj}$: The total quantity of CFBD adjustments in MW is based on the summation of the adjustment for: 1) negative adjustments for Demand Response, 2) positive adjustments to CFBD for Eligible Intermittent Resources, 3) positive Demand adjustments to CFBD 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 EDAM entity 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.

- $CFBD_{RZ,hour,orig}$: The original CFBD.

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

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

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 CFBD 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.

6.8.2.4.2 MSS Adjustment

- All Metered Subsystems (MSS) are required to participate in the RUC procurement process. The 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.

-

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 CFBD 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.

6.8.2.4.4 Eligible Intermittent Resource Adjustment

The Eligible Intermittent Resource Adjustment was replaced with the ability for VERs to bid RCU up to their VER forecast.

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 CFBD 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

6.8.2.4.6 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 CFBD, CAISO reserves the ability to make adjustments to the CFBD 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 CFBD 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.

6.8.2.4.7 Operator Review & Adjustment

The CAISO Operator reviews the CFBD 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.*

6.8.2.5 Day-Ahead Schedules for Supply

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~~6.8.2.4.1~~, RUC Zone Adjustment.

6.8.2.6 Reliability Capacity Bids

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 to the CAISO BAA that are required to participate in RUC must bid no lower than its RA capacity or its RCU certified MW for RCU. Additionally, to facilitate the EDAM Resource Sufficiency Evaluation (RSE), all eligible resources in the EDAM footprint (including non-RA resources) that offer energy bids into the IFM must submit bids for RCU at a quantity no lower than its RCU certified MW or its energy bid plus any ancillary service self-provision. Resource Bids for RCD are optional. An energy bid or self-schedule is required for a resource to be eligible to offer RCU or RCD, except for VERs where an RCU bid is required even in the absence of an energy bid.

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.

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 , 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.

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.

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 6-3: 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)	Non RA Capacity is eligible to Bid (CAISO Tariff: 31.5.1.1, 31.5.1.2)
Constrained Output Generator (COG)	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)	No RUC Availability Bid 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)	Dynamic non-RA Capacity eligible to bid otherwise Other non-RA eligible to bid optionally into RUC (CAISO Tariff: 31.5.1.1)
Non-Resource-	N/A	N/A	Dynamic non-RA

	Start-Up Costs	Minimum Load Costs	RUC Availability Bid
Specific System Resource	(CAISO Tariff: 30.5.2.4)	(CAISO Tariff: 30.5.2.4)	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

6.8.2.7 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.

6.8.2.7.1 Capacity Constraints

The capacity constraints ensure that sufficient Reliability Capacity is procured to meet the CFBD. 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 the total Demand (which includes IFM export Schedules and Demand Forecast.) The CFBD can be adjusted to increase the RUC target if there is AS Bid insufficiency in IFM, as described in Section 6.8.2.3~~6.8.2.3~~ above.

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 CFBD, 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 CFBD.

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

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
- $\%E_{RUC,Limiit}$: 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 CF BD.

Operational factors that are considered in setting this parameter are:

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

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 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[39]

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

6.8.2.7.4 State of Charge Constraints for Storage Resources

Storage resources awarded RCU or RCD in the RUC process are subject to State of Charge (SOC) constraints. The RUC optimization enforces an "SOC Envelope" constraint, similar to the IFM, which creates an upper and lower boundary for the resource's state of charge based on IFM energy schedules and RUC capacity awards. This ensures that the storage resource maintains sufficient energy (to deliver RCU) or sufficient charging headroom (to deliver RCD) to be effectively dispatched in Real-Time. The specific multipliers (attenuation factors) used for these RUC SOC constraints are identified in section in Configurable Parameters.

The following equation reflects the ancillary service state of charge constraint in the day-ahead market for Storage Resources:

$$\left.\begin{aligned} SOC_{i,t} - RU_{i,t} - SR_{i,t} - NR_{i,t} - IRU_{i,t} - RCU_{i,t} &\geq \underline{SOC}_{i,t} \\ SOC_{i,t} + \eta_i \left(RD_{i,t} + IRD_{i,t} + RCD_{i,t}\right) &\leq \overline{SOC}_{i,t} \end{aligned}\right\}, \forall i \in S_{LESR} \wedge t = 1,2,\dots,T$$

The mathematical formulations for the SOC envelope constraint in RUC are:

$$\left.\begin{aligned} SOC_{i,t}^{(u)} &= \begin{pmatrix} SOC_{i,t-1}^{(u)} - EN_{i,t}^{(+)} - \eta_i\, EN_{i,t}^{(-)} - ARU_t\, RU_{i,t} \\ -AIRU_t\, IRU_{i,t} - ARCU_t\, RCU_{i,t} + \eta_i\, ARCD_t\, RCD_{i,t} \end{pmatrix} \geq \underline{SOC}_{i,t} \\ SOC_{i,t}^{(d)} &= \begin{pmatrix} SOC_{i,t-1}^{(d)} - EN_{i,t}^{(+)} - \eta_i\, EN_{i,t}^{(-)} + \eta_i\, ARD_t\, RD_{i,t} + \\ \eta_i\, AIRD_t\, IRD_{i,t} + \eta_i\, ARCD_t\, RCD_{i,t} - ARCU_t\, RCU_{i,t} \end{pmatrix} \leq \overline{SOC}_{i,t} \end{aligned}\right\}$$

The regulation and imbalance reserve awards in RUC are fixed from IFM. The parameters $ARCU_t$ and $ARCD_t$ are configurable attenuation factors (multipliers) attached to the reliability

[39] 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.

capacity awards. The current values for these factors are maintained in the BPM section on configurable parameters.

Cancellation of RCU and RCD in the envelope constraints allow for RCU/RCD awarded by RUC in any given interval to count towards the SOC and enable such SOC to be used for RCU/RCD in future intervals.

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 the bid costs of Reliability Capacity (RCU/RCD) while meeting the adjusted CFBD. 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 CFBD. 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 RCU or commit additional resources either because of insufficient physical supply being scheduled in the IFM (e.g., due to virtual awards) or due to transmission constraints because of differences in the Location and quantity of Demand scheduled in the IFM and the CFBD. Additionally, if the physical supply cleared in the IFM is greater than the CFBD, RUC may procure downward capacity (RCD).

While RUC commits resource capacity from Long-Start and Short-Start Units to meet CFBD, RUC does not automatically de-commit resources in cases of Overgeneration conditions or in cases where the Day-Ahead Schedules exceed the CFBD. 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.

6.8.4 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.

6.8.4.1 RUC Schedules

The total MW per hour amount of capacity committed by RUC including the MW per hour amounts committed in the Day-Ahead Energy Schedule. RUC schedules and prices are both derived from the pricing run.

Reliability Capacity (RCU/RCD) and Awards RCU and RCD Awards are determined as follows:

- Reliability Capacity Up (RCU) is the positive difference between the RUC Schedule and the Day-Ahead Energy schedule of a resource.
- Reliability Capacity Down (RCD) is the negative difference between the Day-Ahead Energy Schedule and the RUC Schedule of a resource.
- The portion of the capacity that corresponds to the Minimum Load is not considered RCU and it is not eligible for 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 Reliability Capacity from a LRMR unit that is used in the RUC optimization to meet CFBD is not eligible for an RCU or RCD Award since the capacity is already compensated through LRMR Contract.
- Any RUC Capacity in excess of LRMR Capacity 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.

6.8.4.2 RUC Reliability Capacity Pricing

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.

6.8.4.3 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 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 RCU Award, but do not receive payment for RUC Start-Up Costs and Minimum Load Costs, as they were never started up.

6.8.4.4 RUC Reliability Capacity Settlement

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

- In the first tier, the Net RCU Bid Cost Uplift is allocated to net virtual supply and under-scheduled load.
- In the second tier, any remaining Net 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 RCU and RCD.

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:

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

5) 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:

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

7) 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.

8) 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'.

9) 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.

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

11) 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.

12) 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

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

- A description of the Real-Time Market timelines
- How CAISO performs the Hour-Ahead Scheduling Process (HASP)

- How CAISO performs the Short-Term Unit Commitment(STUC) process
- A description of the Real-Time Unit Commitment (RTUC) and Fifteen-Minute Market (FMM) processes
- A description of the Real-Time Economic Dispatch (RTED) process
- A description of the Real-Time Manual Dispatch (RTMD) process
- A description of the Real-Time Contingency Dispatch (RTCD) process

A timeline and data flow diagram for the Unit Commitment and Dispatch processes of the Real-Time Market is included.

7.1 Differences from IFM

In general, the RTM applications are multi-interval optimization functions minimizing the cost of dispatching Imbalance Energy and procuring additional AS, when applicable, subject to resource and network constraints. In this respect, the RTM applications are not much different than the IFM application. The main differences are the following:

- The IFM application uses hourly time intervals, whereas the RTM applications use sub-hourly time intervals within their Time Horizon.
- The Time Horizon of the IFM application spans the next Trading Day, whereas the Time Horizon of the RTM applications is variable (due to submission timelines limiting the availability of real-time bids beyond the end of the next hour) and spans the current and next few Trading Hours at most. The RTM applications run at periodic intervals, every 5 or 15 minutes, with a Time Horizon that ends at or beyond the Time Horizon of the previous run. Results for time intervals other than the second (binding) one in the Time Horizon are advisory since they are recalculated the next time the application runs.
- The IFM application uses Demand Bids to clear against Supply Bids, whereas the RTM applications use CAISO Forecast of CAISO Demand and final scheduled exports. Demand Bids and Virtual Bids are not accepted in the RTM.
- The RTM applications use the latest available information about resource availability and network status; in fact, the optimal Dispatch is initialized by the SE solution that is provided by the Energy Management System (EMS).
- The IFM application commits resources optimally for the next Trading Day using three-part Energy Bids. Almost all resources can be considered for optimal commitment,

except for resources with extremely long Start-Up, because the full cost impact of commitment decisions for these resources cannot be evaluated within the IFM Time Horizon. Similarly, the RTM applications that have Unit Commitment capabilities can commit resources optimally within their Time Horizon, however, because that Time Horizon is short (a few hours at most), only Short Start Units can be committed. Consequently, any Long Start Units that are not scheduled in the IFM or RUC, are effectively not participating in the RTM.

- Unlike the IFM application, the RTM applications need to interface with the Automated Dispatch System (ADS) to communicate financially binding commitment and Dispatch Instructions, and with the CAS for confirmation of System Resource Schedules and Dispatch.

- The RTM applications provide more control to the CAISO Operator with the capability to adjust the Imbalance Energy requirements (via adjustments to the Load forecast), block commitment or Dispatch Instructions, or issue Exceptional Dispatches. This CAISO Operator input is necessary to address any unexpected system conditions that may occur in Real-Time.

- The RTM applications also provide the functionality to the CAISO Operator to switch the system or individual resources into a Contingency state under which Contingency-Only Operating Reserves are dispatched optimally to address system contingencies. Contingency-Only Operating Reserves are otherwise reserved and not dispatched by the RTM applications.

- The CAISO Operator may augment or supplant the Dispatch Instructions generated by the RTM application with Exceptional Dispatches if necessary to address system conditions that are beyond the modeling capability of the RTM applications.

- Consistent with WECC Regional Criterion, for CAISO Real Time awards of market priority type RTLPT, RTECON 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 RTLPT or RTECON product-type in the MISC field. 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.

RTLPT and RTECON priority types are not to be combined. 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 CAISO BA, the E-Tag may be subject to adjustment to correspond to the actual Real Time awards, or curtailment based on need following a contingency or resource deficiency in the CAISO when the CAISO is operating in an EEA 3 condition. The MISC field shall include the relevant market priority type RTLPT, RTECON. DALPT priority types may not be combined with RTLPT or RTECON priority types, as each type must be tagged separately.

- In an event of 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.

- The ISO market systems will validate Bids at transmission paths with zero rated TTC in both directions. The details of this procedure are provided in the BPM for Market Instruments. For System Resources that have registered a primary and alternate tie path in the Master File, and were awarded schedules in IFM/RUC on the primary tie, and the primary tie is rated zero in both directions in the real-time, the real-time systems will consider the award to be on the alternate tie for dispatch purposes.

- Unlike the IFM application, RDRR resources will not be selected for normal dispatch unless the CAISO Controlled Grid is in one or more of the following conditions as provided in the associated operating procedures (see CAISO public website):

  - Under system emergencies, including Transmission emergencies; and

  - Mitigating imminent or threatened operating reserve deficiencies; and

  - Resolving local transmission and distribution system emergencies.

In the event these conditions exist, the CAISO operator may choose to activate a software flag that allows these resources to be dispatched. Likewise, after the condition has ended and conditions have stabilized, the operator will reset the flag which will prevent the resources from being dispatched, other than to their day-ahead awarded value. Day-ahead awarded values should be followed in either case. RDRRs with day-ahead schedules will not receive any RT dispatches until operational conditions exist such that the software flag is

activated per condition above. Once activated, the RT dispatch instructions generated will include both DA and RT MW components through ADS per section 7.2.3.5 .

- RDRR resources have the option of discrete dispatch capability in the RTM application. Similar to a COG unit, the RDRR resource selecting the discrete dispatch option will be dispatched either to zero or to a specified MW quantity, and will be allowed to set the LMP if a portion of energy from the resource is needed to serve demand. Unlike a COG unit, the MW quantity is specified via the hourly Energy Bid.

- NGR electing to use Regulation Energy Management can only provide regulation. The ability to provide regulation is dependent on their real-time state of charge. Thus their SOC energy constraint is managed in the Real-Time Economic Dispatch application in combination with EMS only, not IFM or Real-Time Unit Commitment.

- In the RTM application, startup time is included in the Outage time. After an outage has ended, a resource does not also have to have its startup time elapse prior to being considered for commitment, unlike the IFM.

- Startup time for PDRs that 1) registered for the 15-minute or 60-minute bid dispatchable option in the Master File and 2) submit bids into the Real-Time Market will be overridden. RTM will instead consider a 52.5 minute startup time for PDR resources registered for the 60-minute bid dispatchable option, and a 22.5 minute startup time for PDR resources registered for the 15-minute bid dispatchable option.

- For PDR-LSRs, 1) the bid dispatchable option must either be 15-minute or 5-minute. Since this is a single product under two resource IDs in the Master File, the bid dispatchable option must be the same for both PDR-LSR Curtailment Resource ID and PDR-LSR Consumption Resource ID. 2) bids submitted in the Real-Time Market will be overwritten, and instead consider a 22.5 minute startup time for 15-minute bid dispatchable option or 2.5 minute notification time for 5 minute bid dispatchable option.

- In RTM, for purposes of the maximum daily run time constraint, any commitments in IFM are considered binding regardless of whether the resource received a binding day-ahead commitment. RTM may commit resources for additional time periods, but the sum of any IFM commitments and RTM commitments shall not exceed the maximum daily run time constraint.

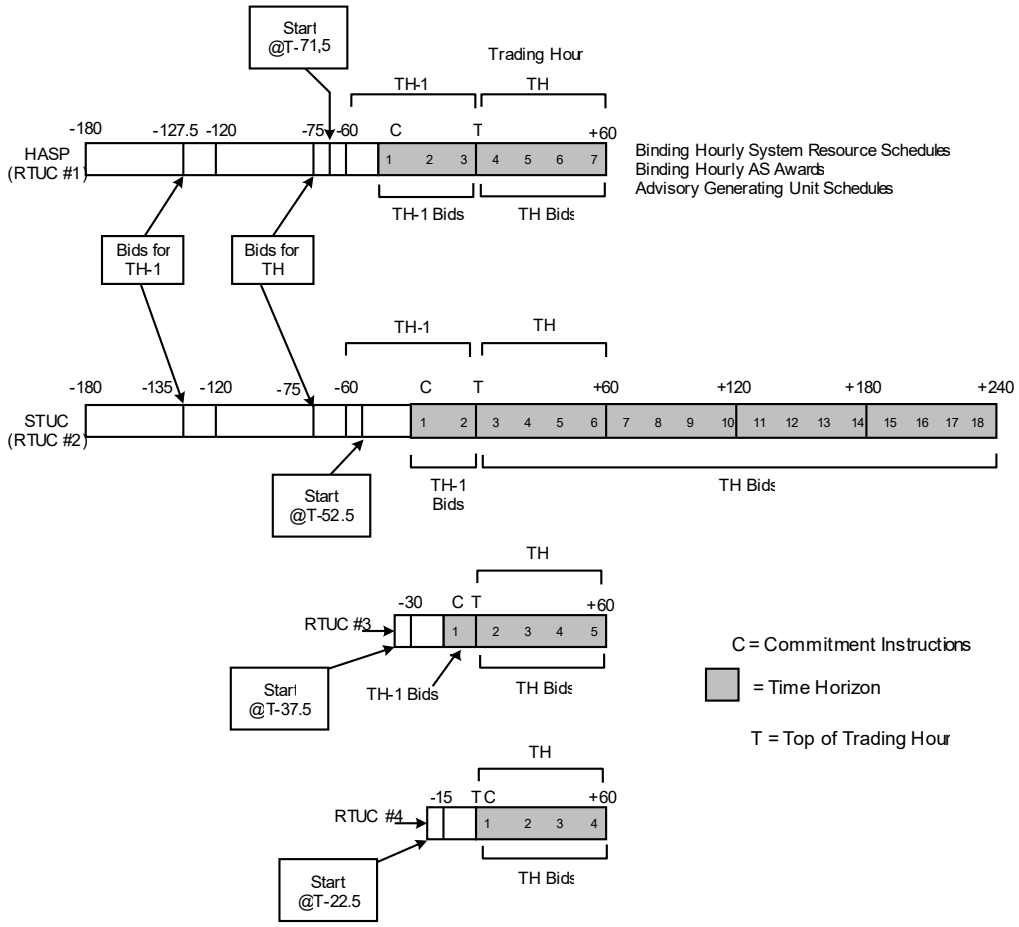
7.1.1 Real-Time Market Timelines

Exhibit 7-1 shows the relationship among the Unit Commitment processes. Each of these applications is described further on in this BPM:

- RTUC/FMM #1 – incorporates HASP, starting approximately 71.5 minutes before the Trading Hour
- RTUC/FMM #2 – starting 52.5 minutes before the Trading Hour
- STUC –starting 52.5 minutes before the Trading Hour
- RTUC/FMM #3 – starting 37.5 minutes before the Trading Hour
- RTUC/FMM #4 – starting 22.5 minutes before the Trading Hour

The timeline for RTM is presented in Exhibit 7-1.The Real-Time Economic Dispatch has a rolling Time Horizon of up to 13 5-minute intervals, executing every 5-minutes at the middle of the 5-minute clock intervals.

Exhibit 7-1: HASP/STUC/RTUC Timelines



7.1.2 Real-Time Dispatch Principles

Generally, the objective of a Real-Time Market is system balancing and Load following on a forward looking basis above and beyond the normal function of the Automatic Generation Control (AGC). Since the RTM is forward-looking, AGC is mainly a control rather than an Energy service. As AGC units depart from their Dispatch Operating Point (DOP) responding to frequency and net interchange deviations, they temporarily supply or consume balancing Energy. The Real-Time Economic Dispatch function dispatches ahead of AGC, while AGC resolves shorter-term imbalances. Irrespective of the particular Dispatch methodology that is employed in a Real-Time Market, the schedule deviations can be classified into "instructed" and "uninstructed".

- Instructed deviations are the result of participating resources responding to Dispatch Instructions. Instructed deviations are usually price setters, whereas Uninstructed Deviations are Price Takers and may be subjected to penalties.

- Uninstructed Deviations may be the result of Load forecast errors, Forced Outages and contingencies, strategic behavior, modeling limitations, failure to follow Dispatch Instructions, etc. Uninstructed Deviations may prompt the response of AGC to balance the system creating Imbalance Energy requirements that are met through instructed deviations calculated optimally by the RTM.

7.1.3 Flexible Ramping Product

Flexible Ramping Product (FRP) is a market-based product, it was developed to address the operational challenges of maintaining power balance in the real-time dispatch. FRP is composed of Flexible Ramping Up (FRU) and Flexible Ramping Down (FRD) capacities. This product is procured in the Real-Time Unit Commitment (RTUC) (which includes the Fifteen Minute Market) and the Real-Time Dispatch (RTD) market. The FRP is resource ramping capacity that is reserved from scheduling or dispatch in the current market to address uncertainty that may materialize in real time. The purpose of FRP is to insure against insufficient ramp capability in real time that may result in extreme prices.

7.1.3.1 Flexible Ramping Product Market Design

FRP is modeled as ramping capability constraints. Flexible Ramp Up (FRU)/Flexible Ramp Down (FRD) is procured for BAAs having passed the FRU/FRD sufficiency test and capacity

test through a constraint for the extreme uncertainty in the entire BAA group, reduced by the FRU/FRD demand elasticity in that group. For each BAA that has failed the FRU/FRD sufficiency test or capacity test, FRU/FRD is still procured separately from the respective FRU/FRD requirement and only reduced by the demand elasticity in that BAA. Modeling flexible ramping in RTUC helps real-time unit commitment make the correct decisions in creating ramping headroom if it is necessary. The real-time unit commitment decisions are binding if such decisions cannot be revisited in later runs due to physical commitment time constraints. The resource flexible ramping awards and prices from the third fifteen-minute interval in each RTUC process are financially binding. The ISO will also re-optimize the procurement of flexible ramping capability in RTD and awards will be compensated according to the marginal prices in RTD. The resource flexible ramping awards and prices from the second five-minute interval in each RTD process are financially binding.

The CAISO will enforce Transmission Constraints for active and base-only flowgates in the FRP deployment scenarios. Flowgates can be base- or contingency- related constraints. The CAISO will further assess if contingency-related constraints in the FRP deployment scenarios will be enforced. Nomograms will be enforced once the functionality has been fully validated.

7.1.3.1.1 FRP Features

The following are the features of the FRP;

- There is no bidding of FRP and the ISO will not procure FRP in the day-ahead market.
- All resources can provide forecasted movement between market intervals in both the FMM and RTD.
- Only resources that have an economic bid and are dispatchable in RTD can have a flexible ramping award in excess of its forecasted movement.
- Flexible ramping awards over the forecasted movement between intervals is procured to meet uncertainty in the 5-minute net load forecast.
- The ISO does not certify flexible ramping capability as it does for ancillary services.
- The ISO will use the internal DOT to evaluate and award the FRP. For instance, if a variable energy resource is using its own 5-minute forecast for settlement of energy. Ramping capability on this resource will be based upon the ISO forecast of the

resources. The ISO forecast, not the resource's forecast, is used to clear both FMM and RTD.

- The system shall implement a FRU/FRD deployment scenario for each interval in the market horizon where:
    - All FRU/FRD awards are deployed.
    - The demand forecast for each BAA that has failed the FRU/FRD sufficiency test or capacity test is increased by the FRU/FRD requirement for that BAA.
    - The demand forecast for the group of BAAs that have passed the FRU/FRD sufficiency test and capacity test is increased by the FRU/FRD requirement for that BAA group.
    - The FRU/FRD surplus in each BAA that has failed the FRU/FRD sufficiency test or capacity test is fully deployed.
    - The FRU/FRD surplus in the group of BAAs that have passed the FRU/FRD sufficiency test and capacity test is fully deployed.

- The system shall calculate FRU/FRD awards for each interval in the market horizon for each BAA that has failed the FRU/FRD sufficiency test or capacity test in that interval to meet the FRU/FRD requirement for that interval and BAA, reduced by the total FRU/FRD surplus for that interval and BAA. The FRU/FRD surplus effectively relaxes the FRU/FRD requirement at a price curve.

- The system shall calculate FRU/FRD awards for each interval in the market horizon for the group of BAAs that have passed the FRU/FRD sufficiency test and capacity test in that interval to meet the FRU/FRD requirement for that interval BAA group, reduced by the total FRU/FRD surplus for that interval and BAA group. The FRU/FRD surplus effectively relaxes the FRU/FRD requirement at a price curve.

- The Flexible Ramp Up Price (FRUP) of a BAA or BAA group will be the Shadow Price of the upward Uncertainty Requirement constraint, which is the cost sensitivity of relaxing the upward Uncertainty Requirement constraint ($/MWh).

- The Flexible Ramp Down Price (FRDP) of a BAA or BAA group will be the Shadow Price of the downward Uncertainty Requirement constraint, which is the cost sensitivity of relaxing the downward Uncertainty Requirement constraint ($/MWh).

- Since there is no economic bidding, there is no self-provision of FRP or market power mitigation rules applied to flexible ramping awards.

- The ISO preserves ramping capability in the first and second fifteen-minute interval of the RTUC process through a configurable parameter (%). Although the first fifteen-minute interval is not financially binding from a FMM perspective, it is part of the RTUC and as such may issue binding commitments of resources that can be started within its time horizon. The parameter ensures the FRP awards from prior FMMs are preserved in the first and second fifteen-minute intervals in each RTUC process. The value is currently set at 100%.

- If a BAA fails the flexible ramping sufficiency test or capacity test at T-55 minutes prior to the start of the next trading hour, the BAA will have its own FRP requirement and financially binding resource FRP awards and prices in the first 15-minute interval of the trading hour in FMM as the associated RTUC process is executed after the tests at T-55.

7.1.3.1.2 Co-optimizing Flexible Ramping Products with Energy and Ancillary Services

The optimization model applies to both RTUC and RTD. RTUC and RTD both optimize over multi-interval horizons. FRP will be modeled by enforcing ramping constraints in RTUC and RTD. Modeling FRP in advisory intervals enables the optimization to foresee potential problems and take actions accordingly.

The objective function is modified to ensure sufficient ramping capability is maintained in order to meet both forecasted movement and uncertainty. The changes to the constraints involving flexible ramping are as follows.

Upward ramping capability limit: This constraint ensures that a resource's upward ramping award plus the total amount of upward reserves (regulation-up, spinning, and non-spinning) awards does not exceed its upward ramping capability over the market clearing interval.

Downward ramping capability limit: This constraint ensures that a resource's downward ramping award plus the regulation-down award does not exceed its downward ramping capability over the market clearing interval.

Active power maximum limit: This constraint limits the awards of energy schedule, upward reserves and upward FRP to be less than or equal to the resource's maximum operating capability.

Active power minimum limit: This constraint limits the energy schedule minus the awards of regulation-down and downward FRP to be greater than or equal to the resource's minimum operating level.

Upward flexible ramping requirement: This constraint ensures that the total amount of upward FRP awards at least meets the requirement.

Downward flexible ramping requirement: This constraint ensures that the total amount of downward FRP awards at least meets the requirement.

FRP is a 5-minute ramping capability based on the dispatch level and the resource's ramp rate. The RTUC and RTD have different market clearing interval granularity:

• RTUC has 15-minute market clearing interval, and

• RTD has 5-minute market clearing interval.

In the optimization, the ISO will model the average 5-minute ramping capability over the applicable market-clearing interval. The ramping capability over the market clearing interval will be converted to the average 5-minute ramping capability by dividing it by an averaging factor AF (AF = 3 for RTUC, and AF=1 for RTD). If resource A has 60 MW capacity and 1 MW/minute ramp rate, it can be awarded 15 MW ramping capability over in an FMM interval. This can be converted to an average of 5 MW 5-minute ramping capability. The difference between the FMM 5 MW awards will be settled at the RTD flexible ramping price. If the resource is awarded 4 MW 5-minute ramping capability in RTD, the resource must pay back the 1 MW at the RTD flexible ramping price.

7.1.3.1.3 Calculation of Flexible Ramp Requirements

The ISO will calculate the FRU/FRD requirement for each 15 minute interval of the next Trading Hour for each BAA in the EIM Area and for the entire EIM Area, as a function of net demand, demand, solar, and wind forecast.

The ISO will calculate the 5 minute FRU/FRD requirement for each 5 minute interval of the market horizon for each BAA in the EIM area that has failed the FRU/FRD sufficiency test in the corresponding 15 minute interval. The ISO will also calculate the 5 minute FRU/FRD requirement for each 5 minute interval of the market horizon for the group of BAAs that have passed the FRU/FRD sufficiency test in the corresponding 15 minute interval. These will be calculated individually as a function of net demand, demand, solar, and wind forecast.

WEIM Entities will have the following information day prior to help guide them on the uncertainty requirements, but these requirements will update during the day with updated forecast information:

- Threshold caps – shown on OASIS
- Uncertainty Histogram – shown on OASIS

Note: Following FRP deliverability project Flex Ramp Requirements API service is deprecated, it can be used to get the data for trade dates before the FRP deliverability activation. Please use 'Flex Ramp Requirements Inputs and Outputs' report for the requirement amount after the FRP activation.

Additional detail can be found in the Appendix for Market Operations Section N.

7.1.3.1.4 FRU/FRD Awards

The ISO will calculate the FRU/FRD awards for each interval for the group of BAAs that have passed the sufficiency tests in the interval BAA group, reduced by the total FRP surplus for that interval and BAA group. The ISO will also calculate the FRU/FRD awards for each interval for each BAA that has failed the sufficiency test in that interval to meet the FRP requirement for that interval and BAA, reduced by the total FRP surplus for that interval and BAA. The FRP surplus effectively relaxes the FRU requirement at a price curve.

7.1.3.1.5 Demand Curve to Meet Uncertainty

The ISO will procure additional flexible ramping capability using a surplus demand curve to meet the upper (upward) and lower (downward) flexible ramping uncertainty requirements. The amount of surplus flexible ramping procured in both the FMM and RTD markets is dependent on (1) the incremental amount of upward and downward flexible ramp needed to account for net demand forecast uncertainty of the next market run's binding interval (i.e. uncertainty requirement), and (2) the market price of supplying the additional flexible ramping capability to the markets.

Incremental upward and downward uncertainty requirements are provided that track the net forecast error for each hour of the day. Note that the market will not require flexible ramping capacity for a given direction (up or down) when the net demand forecast movement exceeds the uncertainty requirement in the opposite direction.

For example, Figure 1(a) shows the net demand forecast movement is 200 MW in the upward direction. The upper (or upward) uncertainty requirement is 50 MW and shall be considered by the upward surplus demand curve. The lower (or downward) uncertainty requirement for that interval is 220 MW. In this case, only the amount of lower uncertainty in excess of the forecast movement will be considered for the downward surplus demand curve (which is 20 MW). If the downward uncertainty were below 200 MW for that interval, downward flexible ramping capability would not be required.

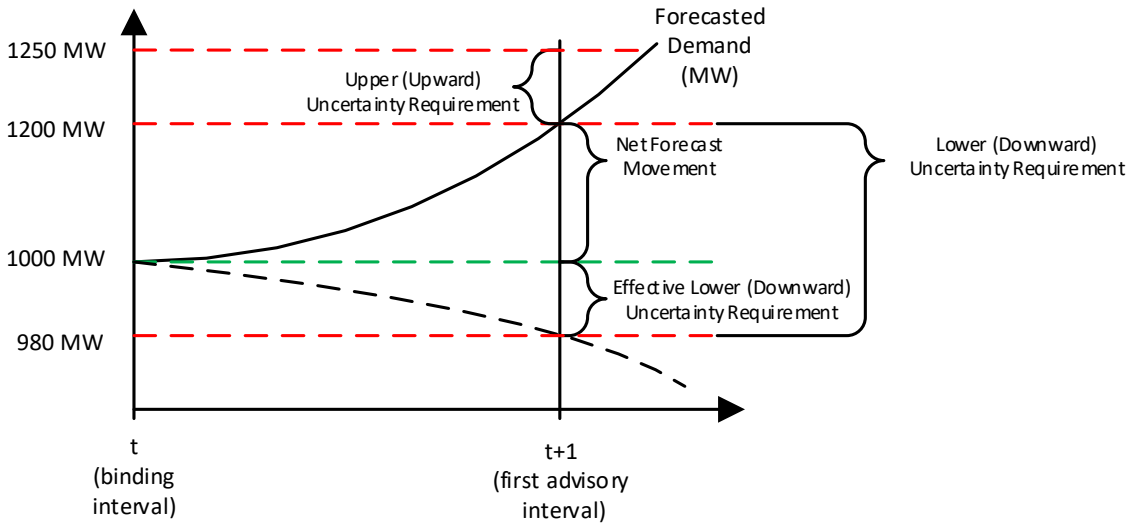


Figure 1 Flexible Ramping Product Uncertainty Requirements

The flexible ramping surplus demand curve will establish the price of not fulfilling the flexible ramping requirement for a given hour over a trade date by applying the flexible ramping cap price to the probability density function from the uncertainty histogram. This allows the market energy price to determine whether all or some of the upward and downward uncertainty requirements are met. In other words, if the energy price is lower than the expected cost of not meeting the flexible ramping uncertainty requirement, more FRP will be procured to cover the ramping requirement uncertainty. Conversely, if the market energy price is above the expected cost, then no additional FRP will be procured to cover the ramping uncertainty requirement.

Further detail on construction of the surplus demand curve can be found in Appendix N.

7.1.3.1.6 Examples

This section presents simple examples of FRP to demonstrate the properties and benefits of flexible ramping under the assumption that net load is accurately predicted.

For simplicity, the examples will only consider the interaction between energy and the flexible ramping product, and ignore ancillary services.

- **Upward flexible ramping**

Assume there are two 500 MW online resources in the system that could provide FRU. The bids and parameters of the two generators are listed in Table 1. G1 has 100 MW/minute ramp rate, and G2 has 10 MW/minute ramp rate. G1 is more economic in energy than G2. They both have zero cost bids for providing flexible ramping.

Table 1: Resource bids, initial condition and operational parameters

Generation	Energy Bid	Initial Energy	Ramp Rate	Pmin	Pmax
G1	$25	400 MW	100 MW	0	500 MW
G2	$30	0	10 MW	0	500 MW

Scenario 1: Single interval RTD optimization without upward flexible ramping with load at 420 MW.

In scenario 1, load is met by the most economic resource G1, and G1 sets the LMP at $25.

Table 2: Single-interval RTD dispatch without upward flexible ramping

	Interval t (LMP=$25)	
Generation	**Energy**	**Flexramp up**
G1	420 MW	-
G2	0 MW	-

Scenario 2: Single interval RTD optimization with upward flexible ramping with load at 420 MW and an upward flexible ramping requirement at 170 MW.

The solution for scenario 2 is listed in Table 3. In scenario 2, in order to meet 170 MW upward flexible ramping, G1 is not dispatched for as much energy to make room for upward flexible ramping. As a result, G1 does not have extra capacity to meet extra load, and LMP is set by G2 at $30. The upward flexible ramping requirement caused the LMP to increase compared with scenario 1. FRU price is set by G1's energy opportunity cost $30 – $25= $5.

Table 3: Single-interval RTD dispatch with upward flexible ramping

	Interval t(LMP=$30, FRUP=$5)	
Generation	**Energy**	**Flexramp up**
G1	380 MW	120 MW
G2	40 MW	50 MW

Scenario 3: Two-interval RTD optimization without upward flexible ramping with load (t) at 420 MW and load (t+5) at 590 MW.

The solution for scenario 3 is listed in Table 4. In scenario 3, there is no flexible ramping requirement. However, the look-ahead optimization projects a 170 MW of upward load ramp from interval t to t+5, which equals the upward flexible ramping requirement in scenario 2. The look ahead optimization produces the same dispatch for interval t as in scenario 2, but different LMPs. The LMPs are different because there is an interaction between the energy price and flexible ramping price. Without the flexible ramping product, the look-ahead optimization still holds G1 back in interval t to meet the load in interval t+5, but G1 is still the marginal unit in interval t and sets the LMP at $25. G2 is the marginal unit for interval t+5 and sets the non-binding LMP for interval t+5 at $35 ($30 bid cost in interval t+5 plus $5 not bid cost not recovered in interval t).

Table 4: Look-ahead RTD dispatch without upward flexible ramping

	Interval t (LMP=$25)	**Interval t+5 (LMP=$35)**
Generation	**Energy**	**Energy**

G1	380 MW	500 MW
G2	40 MW	90 MW

Scenario 4: Two-interval RTD optimization with upward flexible ramping with load (t) at 420 MW and load (t+5) at 590 MW. The upward flexible ramping requirement at (t) is 170.01 MW.

In scenario 4, both flexible ramping and look-ahead are modeled in the optimization. In order to have uniquely determined prices, we set upward flexible ramping requirement slightly higher than expected load ramp 170 MW. The results are listed in Table 5 which converge to scenario 2 in the first interval. If the flexible ramping requirement is slightly lower than the expected load ramp, the solution would converge to scenario 3.

Table 5: Look-ahead RTD dispatch with FRU requirement slightly higher than expected upward load ramp

	Interval t (LMP=$30, FRUP=$5)		**Interval t+5 (LMP=$30)**	
Generation	**Energy**	**Flex-ramp up**	**Energy**	**Flex-ramp up**
G1	379.99 MW	120.01 MW	500 MW	-
G2	40.01 MW	50 MW	90 MW	-

Table 6: Possible look-ahead RTD dispatch without flexible ramping in the interval T+5

Interval t+5	**Load = 589.99 MW**	**Load = 590.01 MW**
G1	500 MW	500 MW
G2	89.99 MW	90 MW
LMP	$30/MWh	$1000/MWh

- **Downward flexible ramping**

Assume two 500 MW resources are online in the system that can provide flexible ramping. The bids and parameters of the two generators are listed in Table 7. G1 has 10 MW/minute ramp rate, and G2 has 100 MW/minute ramp rate. G1 is more economic in energy than G2. They both have zero cost for providing flexible ramping.

Table 7: Resource bids, initial condition and operational parameters

Generation	Energy Bid	Flex Ramp Up	Flex-Ramp Down	Energy Initial	Ramp rate	Pmin	Pmax
G1	$25	0	0	300 MW	10MW/min	0	500
G2	$30	0	0	100 MW	100MW/min	0	500

Scenario 1: Single interval RTD optimization without downward flexible ramping with load at t = 380 MW

The solution for scenario 1 is listed in Table 8. In scenario 1, load is met by both G1 and G2, and G2 sets the LMP at $30. Although G1 is more economic than G2, its output 350 MW has been limited by its ramp rate 10 MW/minute from its initial condition 300 MW, so it cannot set the LMP.

Table 8: Single-interval RTD dispatch without downward flexible ramping

	Interval t (LMP=$30)	
Generation	**Energy**	**Flexramp down**
G1	350 MW	-
G2	30 MW	-

Scenario 2: Single interval RTD optimization with downward flexible ramping with load at t =

380 MW and downward flexible ramping requirement at t = 170 MW

The solution for scenario 2 is listed in Table 9. In scenario 2, in order to meet 170 MW downward flexible ramping, G2 needs to be dispatched up in order to provide downward flexible ramping. As a result, G1's output will be reduced in order to maintain the power balance, and G1 sets the LMP at $25. Note the downward flexible ramping requirement causes the LMP to decrease compared with scenario 1. The downward flexible ramping price FRDP is set by G2's energy price deficit $30 – $25= $5. The FRDP price is to compensate G2 such that G2's revenue including both energy and FRD can cover its energy bid cost $30. As a result, there is no revenue shortage for G2, and no need for bid cost recovery.

Table 9: Single-interval RTD dispatch with downward flexible ramping

	Interval t (LMP=$25, FRDP=$5)	
Generation	**Energy**	**Flex-ramp down**
G1	260 MW	50 MW
G2	120 MW	120 MW

Scenario 3: Two-interval RTD optimization without downward flexible ramping with load at t = 380 MW and load at t+5 = 210 MW.

The solution for scenario 3 is listed in Table 10. In scenario 3, there is no FRD requirement. However, the look-ahead optimization projects a 170 MW of downward load ramp from interval t to t+5, which equals the downward flexible ramping requirement in scenario 2. The look-ahead optimization produces the same dispatch for interval t as in scenario 2, but different LMPs. The dispatch is the same because the look-ahead load ramp also requires the same amount of ramping capability as the flexible ramping requirement in interval t. The LMPs are different because there is an interaction between the energy price and flexible ramping price. When net system demand is decreasing, which creates more downward ramp need, the look-ahead optimization will increase the energy price in the binding interval (for similar but opposite reasons as described in the FRU example in scenario 3 in the preceding section 6.1).

Table 10: Look-ahead RTD dispatch without downward flexible ramping

	Interval t (LMP=$30)	**Interval t+5 (LMP=$20)**

Generation	Energy	Flex-ramp down	Energy	Flex-ramp down
G1	260 MW	-	210 MW	-
G2	120 MW	-	0	-

Scenario 4: Two-interval RTD optimization with downward flexible ramping with load t = 380

MW and load at t+5 = 210 MW. The downward flexible ramping requirement at (t) is 170.01.

In scenario 4, both flexible ramping and look-ahead are modeled in the optimization. In order to have uniquely determined prices, we set downward flexible ramping requirement slightly higher than expected load ramp 170 MW. The solution for scenario 4 is listed as Table 11.

Table 11: Look-ahead RTD dispatch with FRD requirement slightly higher than expected downward load ramp

	Interval t (LMP= $25 , FRDP= $5)		terval t+5 (LMP=$25 , FRDP= $0)	
Generation	**Energy**	**Flex-ramp down**	**Energy**	**Flex-ramp down**
G1	259.99 MW	50 MW	210 MW	-
G2	120.01 MW	120.01 MW	0 MW	-

7.1.4 Schedule Changes

The hourly Schedule change rules described below are applied prior to the SCUC/SCED optimization in RTM and only when there are no Energy Bids or Exceptional Dispatch Instructions in both consecutive Trading Hours (otherwise the hourly Schedule change is calculated optimally by SCUC/SCED):

- All cross-hour Non-Dynamic System Resource schedule changes are performed with the standard schedule-change ramp, which is a smooth linear 20-minute ramp between

hourly Schedules. If applicable, schedule changes across 15-minute intervals within the hour are performed with a smooth linear 10-minute ramp between 15-minute interval schedules.

These rules apply also to PDRs which have registered for the 60-minute or 15-minute bid dispatchable option. And for PDR-LSRs that have registered for 15 minute bid dispatchable option.

- Resources with no Energy Bids or Exceptional Dispatch Instructions in consecutive hours are expected to ramp between hourly schedules symmetrically across hourly boundaries in 20 to 60 minutes (i.e., starting 10 minutes to 30 minutes before the top of the hour, respectively) consistent with the submitted and validated Ramp Rate function (incorporating any reported Outages). If a validated Ramp Rate function does not exist for a resource, RTM uses the maximum (best) Ramp Rate function from the Master File. RTM recognizes the unit's capabilities based on its Operating Point, and it does not ramp the unit at a rate higher than the applicable operational ramp rate within its current operating range. The minimum 20-minute ramp is required for smooth hourly schedule changes and is consistent with intertie scheduling agreements between Balancing Authority Areas. Resources with slower Ramp Rates would have longer ramps, and at the extreme, they would ramp from the middle of an hour to the middle of the next hour. Contrary to cross-interval Ramping, where the entire Dispatch Interval is used for Ramping, resources should ramp across hours between 20 and 60 minutes, because of Energy delivery requirements under bilateral contracts and intertie schedules, and because of Ancillary Services provision eligibility. NGRs and PDR-LSR Consumption Resource are treated differently. If they are not supplying Energy Bids or Exceptional Dispatch Instructions in consecutive hours, they will be expected to ramp instantaneously between schedules at the hourly boundary.

7.1.4.1 Cross-Interval Ramping

The difference between the Dispatch across two consecutive intervals is limited to the ramp capability of the resource within the duration of the interval (15 minutes for FMM and 5 minutes for RTED) based on the applicable Operational Ramp Rate curve reduced by a configurable percentage of the relevant Regulation Awards in both consecutive hours. For Generating Units that start-up or shut-down in a given interval, RTM assumes that the start-up and shut-down occur at the start and end of that interval, respectively. The optimal schedule in that interval is limited to half of the ramping capability plus the relevant Minimum Load. Furthermore, for Regulation, the resource is first ramped into its regulating range at start-up before it can regulate, and it is going off Regulation then it is ramped outside of its regulating range at shut-down.

The following ramping rules apply consistently for all RTM 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: 15 minutes in FMM, 5 minutes in RTED and RTMD, and 10 minutes in RTCD.

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: 7.5min in FMM, and 2.5min in RTED and RTMD.

5) The upward ramp capability of resources starting up through Fast Unit Start-Up (from the applicable Lower Operating Limit) in RTCD would be limited to the difference between 10 minutes and their Start-Up Time.

6) 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 $+\infty$ and the downward ramp capability would extend downwards to $-\infty$ 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.

7) The upward ramp capability of resources across time intervals with Regulation Up Awards would be reduced by the sum of these awards over these intervals, multiplied by a configurable factor.

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

9) By exception, the ramp capability of resources on regulation would not be limited in RTCD.

10) The configurable factor for the upward and downward resource ramp capability reduction would be application specific (FMM, RTED and RTMD) because it would depend on the duration of the time interval.

11) In RTED, in the case a resource is awarded Regulation but the telemetry is outside the Regulation range, the resource is ramped at the Operational Ramp-Rate, with no ramp capability reduction, towards the dispatch level that is inside the Regulation range by an amount to support the awarded Regulation until the resource is actual able to support the regulation awarded.

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.

7.1.4.2 Multi-Stage Generating Resource Constraints

- The following constraints are modeled for Multi-Stage Generating Resources in addition to the typical constraints for Generating Units or Dynamic Resource-Specific System Resources:
- The start-up notification time will be enforced for each startup-able MSG Configuration. Start-up notification time is used to determine how far ahead the startup instruction has to be issued.

- The MSG Configuration transition parameters may differ for each feasible transition. The feasible transitions have specified transition notification times, transition ramp times, and Transition Costs in the Master File.

- The SCUC optimization process considers bid-in costs (including Energy Bids and Ancillary Services Bids, Start-Up Costs, Minimum Load Costs, and Transition Costs.

- The MSG model optimally assigns Self-Schedule to one MSG Configuration among all MSG Configurations associated with a particular MSG plant.

- The Energy Limit values are specified at the plant level and are enforced at the plant level if defined. In both the RTM and DAM, the Energy Limit calculation will include the transitional Energy between two configurations.

- The MUT, MDT and SUT constraints are ignored for resources that have bid only Self Schedules for the entire optimization horizon.

- Multi-Stage Generating Resources may also specify the daily maximum number of transitions per direction between the on-line configurations. This number defines how many times the MSG resource can be transitioned from one MSG Configuration to another.

- Transition notification time: the notification time represents the time required to be notified in advance of the end of the transition to another MSG Configuration. As a consequence, notification time includes the transition ramp time. When switching a MSG Configuration, the MSG needs the transition specific notification time. During the notification time and while not in transition, the MSG resource is available for dispatch and Ancillary Service Award. During a transition ramping time, the Multi-Stage Generation Resource cannot provide Ancillary Services. For Real-Time Unit Commitment, notification time applies only for online to online configuration transitions. If a Multi-Stage Generation Resource is not online, notification time does not apply and the standard configuration based start-up process applies.

- FMM will use these constraints in observing Day-Ahead Schedules. When the Day-Ahead Market commits the Multi-Stage Generating Resource into a specific MSG Configuration, the later FMM run will check to make sure that the Multi-Stage Generating Resource does not move to another MSG Configuration or offline such that the inter-temporal constraints will prevent the Multi-Stage Generating Resource from observing the MSG Configuration specified by the Day-Ahead Schedule.

7.1.4.3 The Current State and Initial Condition Determination

The Real-Time Dispatch will determine the initial condition for Multi-Stage Generating Resources. The Real-Time Dispatch determines which MSG Configuration the Multi-Stage Generating Resource is operating in for the initial condition of the market time horizon. Some of the Multi-Stage Generating Resources have the capability to notify the currently running MSG Configuration through EMS. This option is provided via a Master File flag. If the MSG plant does not have this capability the currently running MSG Configuration needs to be determined by using the look-up table that contains the number of Combustion Turbines and Steam Turbines connected to the system and their combined power output that maps them to an MSG Configuration.

The following sample data demonstrates this process: Combined Cycle plant ABC has two combustion turbines and one steam unit and has four configurations.

MSG PLANT	MSG CONFIGURATION	NUMBER OF CTs	NUMBER OF STs	RESULTANT LOW MW CAPACITY (Configuration Pmin)	RESULTANT HIGH MW CAPACITY (Configuration Pmax)
ABC	1	1	0	0	100
ABC	2	2	0	100	200
ABC	3	1	1	0	150
ABC	4	2	1	100	250

Each Configuration is identified by the number of the combustion turbine and steam turbine connected to the system. The Real-Time Market application will read the telemetry data and determine how many gas and steam turbines are currently connected to the system and their combined MW output.

In cases where the telemetry data indicates a MW level that falls within an overlap region between two configurations, the MSG Configuration from the previous market run will be used to determine the initial condition configuration for the current run. The MSG resource will remain in its previous state until the telemetry MW eventually falls outside the configuration's range.

The determination if the plant is 'In State' or 'In Transition' is based on the Generating Unit telemetry information. If the telemetry information suggests that the Generating Unit is present in one of the available configurations, the Generating Unit's initial condition is tagged 'In State' (IS). If the telemetry information suggests that the Generating Unit is not in any of the MSG Configurations and is in between configurations, the Generator is tagged 'In-Transition' (IT).

7.1.4.4 Multi-Stage Generating Resource Transition Profile

The Multi-Stage Generating Resource will transit from one MSG Configuration to another by using a transition profile consisting of MW value and time. The MSG Transitions are of two types: Non-overlapping and overlapping type.

Non-Overlapping Transition:

Consider a case where there are gaps in the operating range between the two consecutive MSG Configurations. Let S_1 be the state from which the transition is starting having the operating range $PMin_1$ and $PMax_1$ and S_2 is the state from where the transition is ending have the operating range $PMin_2$ and $PMax_2$ such that $PMin_1 \leq PMax_1 < PMin_2 \leq PMax_2$.

When transitioning from S1 to S2 the state transition starts from PMax1 and ends at PMin2 using the transition time specified in the Master File. The Day-Ahead Market and Real-Time Market will calculate the linear ramping profile using the transition time for internal imbalance consideration. The dispatch will stay at the closest boundary of the "from" configuration until the transition is complete.

Overlapping Transition:

In this case there are no gaps in the operating range between the two consecutive MSG Configurations. Let S1 be the state from which the transition is starting have the operating range PMin1 and PMax1 and S2 is the state from where the transition is ending have the operating range PMin2 and PMax2 such that PMin1 ≤ PMin2 ≤ PMax1 ≤ PMax2 .

When transitioning from S1 to S2 the transition begins and ends in [PMin2, PMax1] and vice versa using the transition time specified in the Master File. The transition will be done by using a pre-calculated transition profile using the transition time for the binding and advisory intervals. The granularity of the transition profile will be same as the time interval of the specific application. The transition profile in this case will be straight line at the middle of the overlapping transition region. As an example if a Multi-Stage Generating Resource has two MSG Configurations as (20-100) MW and (80-200) MW, the transition profile will be a straight line at 90 for the transition time. For overlapping transitions, the dispatch will be assumed at the middle MW level of the overlapping transition region until the transition is complete.

In cases where the transition time is less than the particular application's time interval the instantaneous transition will be achieved. Also, in cases where the lower limits of the higher MSG Configuration and the higher limit of the lower MSG Configuration coincide with each other, and the transition time is zero, then the transition is instantaneous.

7.1.5 Dispatch Priorities

SCUC and SCED alert the CAISO Operator with the aggregate Load increase or reduction in the penalty region for each defined LAP so that the CAISO Operator can procure the required Imbalance Energy through an Exceptional Dispatch.

The SCUC/SCED software provides the functionality to classify and prioritize constraints among themselves and the resource Dispatch priorities. The priority level for any resource or Constraint class is configurable. Resource and Constraint classes may share the same priority level. The penalty prices for all resource priorities, i.e., the price of uneconomic Bid segments for resource bids, e.g., Self-Schedules, RMR dispatches (LRMR only), contingent spin/non-spin, etc., and the penalty prices for Constraint violations are coordinated through the parameter maintenance effort.

The CAISO through the simultaneous optimization to the extent possible will attempt to enforce constraints using Effective Economic Bids. In the event that such constraint(s) are binding and cannot be resolved using Effective Economic Bids and there are conflicting constraints, the CAISO will resolve such conflicting constraints in the priority order mentioned below. The following constraint classes are supported and in the following priority order from high to low:

- Power Balance Constraint
- Base case transmission constraints (separate levels for branch flows, interface flows, and Nomograms)
- Contingency constraints (branch flows)
- Ancillary Services minimum regional requirements
- Ancillary Services maximum regional requirements

The SCUC/SCED software is configured to incorporate any transmission constraint limit adjustments made by CAISO operators to respond to system conditions. The CAISO operators make these adjustments in accordance with section 2.1.1 of the Business Practice Manual for Managing Full Network Model. When a limit is manually adjusted or conformed, the market software will automatically determine if the newly conformed limit is feasible or within the ramping capability in the market. If the newly conformed limit is not feasible or beyond the ramping capability to resolve the constraint, the market optimization will adjust the conformed limit as needed such that the conformed limit will be feasible or the ramping capability will be sufficient to resolve the constraint.

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. Consistent with section 34.1.1 o 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 schedules. For exports, self- schedules in real-time will be based on the RUC 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, or are under a Resource Adequacy Obligation. 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 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 <u>increasing</u> 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[40] (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-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.

[40] 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.

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.

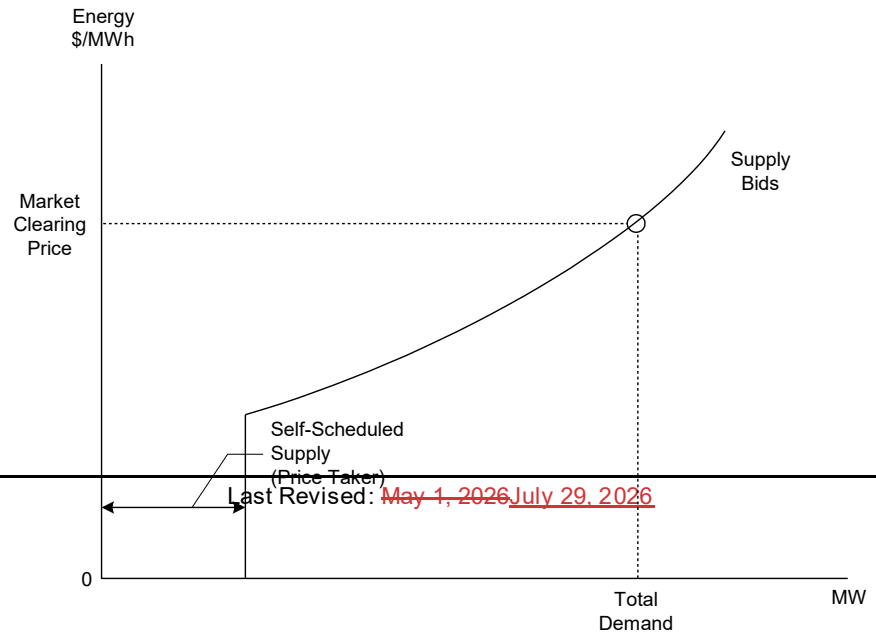
2. For the MSG Configuration with a PMin lower than or equal to the Self-Schedule MW and a PMax higher than or equal to the Self-Schedule MW:
   - Start-Up Costs and Minimum Load Costs are treated as must-run resources (i.e. there is no Start-Up Cost and no Minimum Load Cost);
   - Ignore Transition 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.

7.1.7 Calculation of MCP

Exhibit 7-2 illustrates how the Market Clearing Price for Energy for a HASP time interval is calculated for the case with no Marginal Losses and no Congestion. In this scenario all the LMPs for Energy have the same value, equal to the MCP.

The major difference between this exhibit and the corresponding Exhibit 6-3 for DAM is that RTM has no Demand Bids. Therefore the MCP is established by the Supply curve and the total Real-Time Demand.

Exhibit 7-2: Real-Time Market Clearing Price for Energy (Ignoring Marginal Losses &



Congestion)

7.2 Scheduling Coordinator Activities

The SCs are the entities that interact directly with the RTM. They are responsible for submitting Bids into the CAISO Markets and to respond to the directives of CAISO, resulting from the CAISO Markets. All Settlement and billing is conducted between CAISO and the SCs.

7.2.1 Submit Bids

This section is based on CAISO Tariff Section 34.1.3, Submission of Bids for the RTM.

SCs may submit Bids that are used for the RTM processes starting from the time Day-Ahead Schedules are posted until 75 minutes prior to each applicable Trading Hour in the Trading Day. The rules for submitted Bids specified in Section 30 of the CAISO Tariff apply to Bids submitted to the RTM.

After the bidding closes for the RTM for a Trading Hour, CAISO performs a validation process consistent with the provisions set forth in Section 30.7 of the CAISO Tariff, and described in more detail in the *BPM for Market Instruments, Section 8*.

Bids submitted to the RTM to supply Energy and Ancillary Services are considered in the various RTM processes, including the MPM process, the HASP, the STUC, the RTUC, the FMM, the RTED, the RTCD, and the RTMD.

CAISO allows RTM Self-Scheduled firm exports to the extent the firm export is being physically sourced from a resource that is not obligated to serve CAISO Demand (i.e., capacity being committed to Resource Adequacy, RUC Award). Validation and accommodation for such Self-Scheduled firm exports requires a manual process.

Refer to the *BPM for Market Instruments* for additional bidding details.

7.2.2 Interchange Transactions & E-Tagging

When submitting interchange transactions in the RTM, it is necessary to create an E-Tag. An E-Tag is required for all Energy Schedules and AS Awards at Scheduling Points, in accordance with NERC and WECC specifications. See section 8.0 for more information on tagging.

7.2.2.1 E-Tagging Timelines and Rules

See section 8.0 for more information on rules and timelines

7.2.3 Respond to Commitment & Dispatch Instructions

Upon publication of Schedules and Awards, SCs are advised to review the Schedules and Awards in order to be prepared to respond to Dispatch Instructions issued from ADS and CMRI. Start-Up Instructions may be issued by the CAISO before Dispatch Instructions are issued, which require resources to Start-Up prior to the relevant Dispatch Interval. Resources must be started in time for the resource to be available for the Dispatch Interval for which they are committed. The following instructions result from the Real-Time applications.

7.2.3.1 Commitment Instructions

Binding commitment instructions are generated and sent through ADS every 15 minutes from RTUC for dispatchable resource. Shut-Down instructions in the first interval of the RTUC Time Horizon are always binding. Shut-Down instructions in subsequent intervals are advisory and thus not sent through ADS. Start-Up instructions are binding if they cannot be revised in subsequent RTUC runs due to the relevant Start-Up Time. Only binding Start-Up instructions are sent through ADS. Transition Instructions are binding if they cannot be revised in subsequent Real-Time Unit Commitment runs due to the relevant transition notification time. Only binding transition instructions are sent through ADS

7.2.3.2 Ancillary Service Awards

AS Awards are generated and sent through ADS and CMRI for all resources except Non-Dynamic System Resources that have submitted any type of hourly block bids every fifteen minutes, as required for dispatchable resources. For Non-Dynamic System Resources that have submitted hourly block bids, AS awards will be sent to ADS and CMRI for the target hour once an hour after each associated HASP run. The AS Award separately identifies the Day-Ahead Award, the Real-Time qualified self-provision, and the Real-Time AS Awarded Bid. Any Real-Time Award for Spinning and Non-Spinning Reserve are considered Contingency Only. AS procurement in the RTM is done optimally based on system conditions during each 15-minute FMM interval. Resources that have Regulation awards or schedules must stay on Automatic Generation Control until the end of the 15-minute FMM interval. Because the CAISO must then maintain adequate reserves during the 15-minute interval, with no further opportunity for AS procurement, the RTM AS Awards are protected from being dispatched by RTED through designation as "contingency only". The CAISO will not Dispatch any Energy from the

associated Energy Bid if there is no Ancillary Services awarded to the Non-Dynamic System Resource. See CAISO Tariff Section 30.5.2.6 and the BPM for Market Instruments.

7.2.3.3 Exceptional Dispatch

Exceptional Dispatches can be generated and sent through ADS or issued through manual instructions. When generated through Ads, instructions are reported and updated when they are issued. These instructions arrive along with Dispatch Operating Target (DOT) and possibly Unit Commitment instructions.

It is possible that there is more than one non-conflicting Exceptional Dispatch for the same time period. ADS presents those instructions.

Refer to Section 7.11, Exceptional Dispatch, for additional information.

7.2.3.4 Dispatch Instructions

Dispatch Instructions, also referred to as Dispatch Operating Targets (DOTs), for dispatchable resources, including Dynamic System Resources, are generated and sent through ADS every five minutes (or after RTCD). Dispatch Instructions for Non-Dynamic System Resources are generated by HASP or FMM. Non-Dynamic System Resource HASP Block Intertie Schedules and FMM first interval advisory schedules are sent through ADS hourly. Non-Dynamic System Resources HASP Block Intertie Schedules have the option to decline or partially accept a HASP generated Dispatch Instruction. The under/over delivery charge shall apply to intertie resources awarded in the day-ahead market, hour-ahead scheduling process, incremental and decremental changes between the day-ahead market and hour-ahead scheduling process, and the 15-minute market.

The under/over delivery charge shall apply to both hourly block and 15-minute dispatchable intertie resources.

7.2.3.5 Dispatch Instruction Breakdown

Each Dispatch Instruction is broken down into separate MW components. MW components include:

- SCHD: Day-Ahead Schedule
- MSSLF: MSS qualified Load Following Instruction
- RMPS: Standard Ramping Energy
- SUPP: Imbalance Energy
- SPIN: Dispatched Spinning Reserve
- NSPN: Dispatched Non-Spinning Reserve

These breakdowns are associated with their corresponding Dispatch Instructions. This DOT breakdown is published through ADS. The Operators reviews the Dispatch Instructions before they are sent to ADS and they may decide to block certain instructions based on information known to them, but unknown to the RTM application. The Operator may also block all instructions at extreme conditions when the dispatch results are incorrect.

7.2.3.6 Trajectory Data

The Dispatch Operating Point (DOP) is a piecewise linear curve defined by MW (on the Y axis) across time (on the X axis). The source data consists of the DOTs, which are published in the GOTO field in the ADS. The DOP is the expected trajectory of the resource operating point as it ramps from one DOT to the next; the ramping across Dispatch Intervals is linear, unless the operational ramp rate of the resource changes during the ramp.

As part of the requirement to respond to Dispatch Instructions, a resource should follow its DOP. This requirement applies to all resources, including:

- A Non-Generator Resource ramping from one DOT to the next;
- An Eligible Intermittent Resource when ramping from one DOT to the next pursuant to a negative supplemental Dispatch Instruction or Operating Instruction and when sufficient fuel (solar irradiance or wind) permits.

When an Eligible Intermittent Resource is producing as capable, i.e. when its DOT is equal to its forecasted output, the Eligible Intermittent Resource may be producing at a value below or above its forecasted output. Nevertheless, when ramping to a new DOT below its forecasted output, the Eligible Intermittent Resource should still follow a controlled ramp (*i.e.* a linear trajectory from its current output across the Real-Time Dispatch Interval) to reach its new DOT. Similarly, when an Eligible Intermittent Resource returns to produce as capable at the end of a negative supplemental Dispatch Instruction or Operating Instruction, the Eligible Intermittent Resource should follow a controlled ramp between Real-Time Dispatch Intervals.

When a Non-Generator Resource that is a Co-located Resource deviates from a Dispatch Instruction pursuant to CAISO tariff section 34.13.3, the resource should follow a controlled ramp between Real-Time Dispatch Intervals.

For an inverter-based resource without a plant controller or without the capability to follow Dispatch Instructions, by linearly ramping from one DOT to the next, the resource's ramp rate may not exceed 20 percent of its PMax over a 5-minute period.

Since RTM dispatches resources based on their actual output as shown in the State Estimator solution or the telemetry, nearly vertical corrections to the DOP curve can occur at five-minute intervals when a previously issued DOT is corrected to the actual output. In the absence of Dispatch instructions, ADS extends the most recent DOP value available and plots a flat curve to the end of the next interval.

Notwithstanding the above, MSS Load following resources may deviate from the Dispatch Instructions in Real-Time to facilitate the following of Load.

For Generating Units that start up or shut down in a given interval, RTM assumes that the start-up and shut-down occur at the start and end of that interval, respectively. The dispatch in that interval is limited to a ramp capability that corresponds to half of the interval duration, plus the relevant Minimum Load.

For Multi-Stage Generating Resources that are transitioning from one on-line configuration to another, the Real-Time Market assumes that the transition occurs for the time period as defined by the transition ramp time. During the transition time period, the Real-Time Market will assume the Multi-Stage Generating Resource operates in the "from" configuration until the transition is complete. More specifically:

1. During the transition between two non-overlapping configurations, the Real-Time Market will dispatch the resource to stay at the closest boundary of the "from" configuration until the transition is complete. When transition is complete, the Real-Time Market will start the dispatch at the closest boundary of the "To" configuration;

2. During the transition between two overlapping configurations, the Real-Time Market will dispatch the resource to stay at the middle MW level of the overlapping capacity range between those two configurations. When the transition is complete, the Real-Time Market will start the dispatch to ramp within the "To" configuration based on the "To" configuration's ramp-rate.

Resources that have Regulation awards or schedules must stay on Automatic Generation Control until the end of the 15-minute FMM interval. At the end of the FMM interval and when there is no Regulation schedule in the next FMM interval, resources can go off Automatic Generation Control and then ramp linearly to the next RTD DOP.

7.2.3.7 Compliance

When a resource demonstrates that it is not following Dispatch Instructions, consistent with the procedure described below, the RTM will no longer assume that the resource will comply with subsequent Dispatch Instructions.

a) General Compliance Rules

If the CAISO determines there is a need to set the DOT of resources consistent with their actual behavior because of demonstrated non-compliance with Dispatch Instructions, the CAISO will activate the compliance feature. Once activated, a resource is considered non-compliant if it is deviating by more than a threshold (set to five MW or three percent, whichever is greater) from the DOT that was issued for the same time with the timestamp of its telemetry, for more than a configurable number of consecutive intervals (initially set to three). When a resource is flagged as non-compliant, it is fixed in RTM for the entire Time Horizon at its current telemetry. However, the previous DOT that was last issued is sent through ADS. That DOT is continuously sent through ADS for as long as the resource remains non-compliant.

The resource will be considered compliant again when its telemetry comes within the threshold from the DOT for a configurable number of consecutive intervals (initially set to one). The CAISO may also set the resource to be compliant again as necessary.

When a resource has an uninstructed start-up, the resource is automatically considered non-compliant until it either shuts down or until the time of a scheduled start-up (if the resource has an uninstructed early start-up). Similar concept applies to delayed shutdown.

b) Compliance with Dispatches In and Through Forbidden Operating Region

Consistent with the requirements in Section 34.15.1(b) of the CAISO Tariff and Section 7.8.2.4 above, the compliance flag is applied to resources in all intervals of the Real-Time Market to ensure the availability of the resource in intervals, when despite a CAISO Dispatch Instruction into and through a Forbidden Operating Region, the resource never actually enters the Forbidden Operating Region. Consequently, in the event that the RTM functionality identifies that a resource has failed to move into its Forbidden Operating Region as instructed by the CAISO in a Dispatch Instruction, the ISO's systems will set the resource's DOT and initial conditions outside the boundary of the Forbidden Operating Region from which the resource was intended to enter the Forbidden Operating Region. In other words, if a resource is dispatched into a Forbidden Operating Region from above its upper boundary, and the RTM functionality identifies that the resource has failed to move into its Forbidden Operating Region, the resource's DOT and initial conditions will be set outside the upper boundary. Conversely, if a resource is dispatched into a Forbidden Operating Region from below its lower boundary, and the RTM functionality identifies that the resource has failed to move into its Forbidden Operating Region, the resource's DOT and initial conditions will be set outside the lower boundary. As such, the resource will be identified as outside of it's FOR and available to for economic dispatch by the RTM.

7.3 CAISO Activities

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

7.3.1 Accept Real-Time Market Inputs

This section lists the inputs that are common to the Real-Time processes. The inputs that are submitted for the DAM that are also used in the Real-Time process are not repeated here. Note that Real-Time Bids can be submitted after the DAM results are published.

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[41], 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[42] 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 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.

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

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

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.

7.3.1.2 Ancillary Service Award Allocation on Energy Bids

Refer to the description given in Section 4.2.2 of this BPM.

7.3.1.3 Resource Capacity Constraints

RTM optimally commits and dispatches resources to balance Supply and Demand subject to resource and network constraints. Capacity constraints limit the Energy Dispatch and the AS Awards to the available resource capacity or the applicable MSG Configuration's capacity for a Multi-Stage Generating Resource as follows:

- On-line resource not scheduled for Regulation:
  - The Energy Dispatch must be greater than or equal to the lower operating limit.
  - The sum of the Energy Dispatch and the Non-Spinning and Spinning Reserve Awards must be less than or equal to the lower of the upper economic limit or the upper operating limit.
- On-line resource scheduled for Regulation:
  - The Energy Dispatch minus the Regulation Down Award must be greater than or equal to the higher of the lower regulating limit or the lower operating limit.
  - The sum of the Energy Dispatch and the Non-Spinning and Spinning Reserve Awards must be less than or equal to the upper economic limit.
  - The sum of the Energy Dispatch and the Non-Spinning, Spinning, and Regulation Up Awards must be less than or equal to the lower of the upper regulating limit or the upper operating limit.
- Off-line resource awarded Non-Spinning Reserve:

- The Energy Dispatch must be zero.
- The Non-Spinning Reserve Award must be less than or equal to the lower of the upper economic limit or the upper operating limit. No energy Bid is required if the Non-Spinning Reserve Award is less than or equal to the Minimum Load.

Where:

- The lower operating limit is the resource Minimum Load adjusted by any applicable overrates[43]
- The upper operating limit is the resource maximum capacity adjusted by any applicable derates
- The upper economic limit is the highest operating level in the resource Energy Bid
- The lower regulating limit is the lowest operating level below which the resource cannot regulate
- The upper regulating limit is the highest operating level above which the resource cannot regulate

Further details on Upper and lower operating limits are given in Section 4.2.3, Ancillary Service Award Allocation of Energy Bids, and Exhibit 6-4, Capacity Available for RUC.

For resources on regulation with two regulating ranges, the regulating range for the current operating hour is obtained from EMS. The regulating range for the following operating hours is determined based on which range can accommodate Day-Ahead Regulation Down Award immediately below the Day-Ahead Schedule, and a simultaneous dispatch of Day-Ahead Regulation Up, Spinning Reserve, and Non-Spinning Reserve Awards, above the Day-Ahead Schedule. In the case where both regulation ranges can accommodate all Day-Ahead AS Awards, the lower regulation range that contains the Day-Ahead Schedule will be selected. If an Exceptional Dispatch would take a regulating unit outside of the EMS regulation range (for the current operating hour) or the selected regulating range (for the following operating hours), RTM will assume that the unit is taken off regulation.

[43] 'An "overrate" is the opposite of a "derate": an "overrate" restricts a resource's operating range above its lower operating limit, in contrast to a "derate" that restricts its operating range below its upper operating range.

The AS Awards include the relevant DAM AS Awards, any qualified AS self-provision, and the selected incremental AS Awards in FMM. The Energy Dispatch and the selected AS Bid are decision variables, optimally determined to minimize the Energy and AS procurement cost over the entire Time Horizon. When making a decision to shut down a resource in RTM, minimum load costs that arise as a result having to maintain a resource online to allow a resource to meet its day-ahead binding commitment while ensuring the resource does not violate the resources minimum down time may be considered prior to time the resources minimum down time becomes binding. It is important to note that Spinning and Non-Spinning Reserve self-provision requires an Energy Bid for qualification in the RTM, unlike the DAM. Regulation Up Bids can be selected irrespective of the presence of an Energy Bid.

Real-Time AS Awards awarded in FMM are settled at the relevant ASMP. When resource capacity constraints are binding at the optimal solution, the LMP reflects the opportunity cost of the resource capacity that is reserved from dispatching Energy in order to provide AS.

7.3.1.3.1 Minimum Down time for Longer-Start Resources in Real-Time Market

Longer start and extremely long start resources may receive day-ahead market awards in different hours exactly separated by their minimum downtime, requiring the unit to cycle (shutdown to then start up later). Under this scenario, should the real-time market optimization keep the resource online beyond its hourly day-ahead schedule that would violate the resource's minimum down time requirement, the real time market would be forced to keep the resource online throughout the period to honor the minimum down time. This could result in extended operations of these longer-start resources.

Exclusively for long start and extremely long start resources with a minimum downtime exceeding 255 minutes, the real-time market will treat day-ahead shutdowns of these longer-start resources as binding commitments when the resource's minimum down time is exactly equal to the time between shut-down and the time between the next day-ahead market award. This will ensure there is sufficient time for the resource to cycle, honor the minimum down time, and start-up in time for their later day-ahead schedules. However, if continued operation of the unit is necessary for reliability purposes, the resource may be subject to an Exceptional Dispatch or manual dispatch (ED/MD) with a Minimum Generation Output (MinGoto) at the resource's Pmin. An ED/MD will ensure that the resource remains online while allowing the real-time market to dispatch the resource in accordance with economic signals and system reliability needs.

Examples:

1. A resource with a four-hour minimum down time receives the following Day Ahead RUC Schedules across the hours of the operating day. The highlighted red cells reflect the unit is offline to comply with its four-hour minimum down time. The highlighted green cell indicates an additional contiguous hour where the unit is scheduled to be offline. Together, the hours in the green and red cells display a total gap between a shutdown and a subsequent start up on a given day. Here, the market is not required to issue a binding shutdown in HE12 because the resource has sufficient time to honor its minimum down time should the real-time market keep the resource online into HE12. As system conditions may change from the day ahead award publishing, RTPD may keep the resource online as part of its real time optimization in HE12.

HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
ResX	50	50	50	50	50	50	50	50	50	50	50	0	0	0	0	0	50	50	50	50	50	50	50	50

2. However, should the resource remain online through HE12, the real-time market will issue the HE13 shutdown instruction as binding to ensure the resource can honor its minimum down time before its next hourly award at HE17. The real-time market will not consider keeping the resource on as part of its optimization.

HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
ResX	50	50	50	50	50	50	50	50	50	50	50	50	0	0	0	0	50	50	50	50	50	50	50	50

Section 34.7 of the CAISO tariff sets forth general dispatch principles under which the market produces feasible awards to meet projected Energy and Uncertainty Requirements over the applicable forward-looking time-period, subject to transmission and resource operational constraints. Without the logic described in this section, the real-time market may dispatch a resource in a way that does not respect its minimum downtime and, impairing the resource's ability to meet to meet its future day-ahead awards.

7.3.1.4 End-Of-Hour State-Of-Charge Bid Parameter

The end-of-hour (EOC) state-of-charge (SOC) bid parameter is an optional, real-time only bid parameter for NGR resources to allow for easier management of the SOC in real-time. The EOH SOC is an hourly value submitted as a range with an upper and lower state of charge limit. The market will dispatch the resource so that the SOC ends the hour within the submitted range, while respecting Master File and minimum and maximum energy bid limits. Ancillary service awards will be protected above the EOH SOC bids, in accordance with the SOC requirements described in section 2.5.9 of this BPM. However, a resource may receive uneconomic energy dispatches if necessary to achieve the EOH SOC submitted by the scheduling coordinator.

Bid cost recovery for resources that submit state-of-charge parameters will be settled pursuant to Section 11.6.6 of the tariff.

7.3.2 Close Real-Time Market

The Real-Time Market is closed at 75 minutes before the beginning of the Trading Hour.

7.3.3 Execute Real-Time Applications

The following Real-Time applications are executed by CAISO after bidding for the market closes:

- MPM (every 15 minutes) for RTUC, every 5 minutes for RTD)
- RTUC/FMM (every 15-min)– #1 incorporates HASP
- STUC (hourly)
- RTED (every 5 minutes)
- RTCD (on demand)
- RTMD (on demand)

The table shown by Exhibit 7-3 summarizes the execution of these applications.

Exhibit 7-3: Real-Time Applications

Application	Periodicity	Interval	Time Horizon	Task

Application	Periodicity	Interval	Time Horizon	Task
RTUC/FMM	15-min Beginning at midpoint of each 15-min period	15-min	105-60 min	Unit Commitment for the 105-60 min Time Horizon. 15-min AS Awards for the second 15-min interval of the Time Horizon.
MPM	15-min Beginning at midpoint of each 15-min period 5-min Beginning at midpoint of each 5-min period	15-min 5-min	105 min 55-65 min	Market Power Mitigation for RTM Bids submitted at *T*–75' for the Trading Hour from *T* to *T*+60'.
HASP See Note 1	Hourly	15-min	105 min ,	Hourly pre-dispatch for hourly block Bid System Resources for the Trading Hour from *T* to *T*+60'. Advisory 15-min dispatch for all other resources for the Trading Hour from *T* to *T*+60'. Advisory 15-min AS Awards for resources for the Trading Hour from *T* to *T*+60'. Binding hourly AS Awards for Non-Dynamic System Resources for the Trading Hour from *T* to *T*+60'.
STUC	Hourly Beginning at *T – 52.5*'	15-min	270 min	Unit Commitment for the Time Horizon from *T*–30' to *T*+240'.
RTED	5-min Beginning at midpoint of each 5-min period	5-min	55-65 min	5-min Dispatch for Dynamic System Resources and Generating Units for the first 5-min interval of the Time Horizon.
RTMD	On demand	5-min	5-min	5-min Dispatch for Dynamic System Resources and Generating Units.
RTCD	On demand	10-min	10-min	10-min Dispatch for Dynamic System Resources and Generating Units. 10-min Dispatch for Non-Dynamic System Resources AS Energy

Application	Periodicity	Interval	Time Horizon	Task
Note 1: The HASP functionality is embedded in the RTUC application; the first of the four RTUC runs performs the HASP function.				

7.3.4 Publish Real-Time Market Reports to Scheduling Coordinators

The following is a summary of the Real-Time Market reports available to SCs for online viewing:

- **Real-Time MPM Results** – Information about the mitigated Bid that is used if the original Bid is modified in the RTM.
- HASP hourly Energy Dispatch and AS awards for Non-Dynamic System Resources that have submitted Hourly Block Bids.
- HASP 15-min advisory Energy Dispatch and Ancillary Services Awards for all other resources.
- FMM 15-min Energy and Ancillary Services Awards, both for the binding interval and the advisory intervals in the RTUC time horizon.
- **Hourly Inter-SC Trades** – Inter-SC Trade Schedules for both Trades at Aggregated Pricing Nodes and physical trades, for both Energy and Ancillary Services Obligation, as a result of the HASP.

Refer to the *BPM for Market Instruments* for the detailed contents of these reports.

7.4 MPM for Real-Time

This section is based on CAISO Tariff Sections 34.1.5 (Mitigating the Bid Sets Used in the RTM Optimization Processes). For a given Trading Hour, MPM is performed separately in FMM and RTD.

After the Market Close of RTM, after CAISO validates the Bids pursuant to CAISO Tariff Section 30.7, and prior to running FMM, the CAISO conducts the MPM process, the results of which are utilized in FMM.

Prior to FMM, the MPM process performs a DCPA for each interval of FMM (binding and advisories). For a given hour, a Bid that is not mitigated in a given 15min interval of one FMM run may be mitigated in a subsequent FMM run for the corresponding 15min interval. Once a Bid is mitigated in a FMM run for a given 15min interval, the mitigated Bid applies only to that 15min interval and only in that FMM run. The original unmitigated Bid will be evaluated again by the MPM process for the corresponding 15min interval of the next FMM run, if it lies within the market horizon.

For RTD, the MPM process is performed after the RTD solution for a configurable number (currently three) of 5min advisory intervals after the binding 5min interval. The MPM process performs a DCPA on these advisory intervals, the results of which are used to mitigate the Bids for these intervals, which will then be used for the corresponding 5min intervals of the following RTD run. Once a Bid is mitigated in a RTD run for a given 5min interval, the mitigated Bid applies only to that 5min interval and only for the following RTD runs. Bids cannot be unmitigated by subsequent RTD runs. However, a mitigated Bid may be further mitigated in a subsequent RTD run.

Bids from Demand Response Resources, Participating Load, Hybrid Resources, and non-storage Non-Generator Resources[44] 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.

For both Condition 1 and Condition 2 LRMR Units, when mitigation is triggered, an RMR Proxy Bid for each applicable interval is calculated using the same methodology described as for non-LRMR Units. The RMR Proxy Bid will be utilized for the corresponding 15min or 5min interval in FMM and RTD, respectively.

If a Condition 2 LRMR Unit is issued a Manual RMR Dispatch by the CAISO, then RMR Proxy Bids for all of the unit's Maximum Net Dependable Capacity will be considered in the MPM process.

- For a Condition 1 LRMR Unit that has submitted Bids and has not been issued a Manual RMR Dispatch, to the extent that the non-competitive Congestion component of an LMP calculated in the MPM process is greater than zero, and that MPM process dispatches a Condition 1 LRMR Unit at a level such that some portion of its market Bid exceeds the Competitive LMP at the LRMR Unit's Location, the resource will be flagged as an RMR

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

dispatch if it is dispatched at a level higher than the dispatch level determined by the Competitive LMP.

7.5 Hour-Ahead Scheduling Process

This section is based on CAISO Tariff Section 34.2, Hour-Ahead Scheduling Process (HASP).

HASP is the hour-ahead scheduling process during Real-Time. The HASP functionality is included in a special hourly run of RTUC. RTUC utilizes a SCUC optimization and runs every 15 minutes, as described in Section 34 of the CAISO Tariff and Section 7.6 of this BPM. This section describes the special features of the specific hourly HASP run of RTUC.

HASP enables the CAISO to issue hourly pre-dispatch instructions to Non-Dynamic System Resources that submit hourly block Bids to HASP along with HASP Advisory Schedules for Energy and AS Awards for all other participants in the RTM. The hourly pre-dispatch instructions consist of HASP Block Intertie Schedules for Energy and Ancillary Services and HASP Advisory Schedules for Economic Hourly Block Bids with Intra-Hour Option that may change for economic reasons at most once in the Trading Hour.

These rules apply also to PDRs which have registered for the 60-minute or 15-minute bid dispatchable option. And PDR-LSRs that have registered for 15-minute bid dispatchable option.

7.5.1 HASP Inputs

This section describes the inputs that are specific to HASP, excluding those inputs that are common to all the Real-Time processes.

7.5.1.1 RTM-CAS Interface

Control Area Scheduler (CAS) is the application where all System Resource Schedules, and Dispatch Instructions are logged. HASP Energy Schedules and Exceptional Dispatch Instructions are first sent by RTM to ADS and CAS, and then confirmed by CAS for use in future RTM runs. Because System Resource Dispatch needs to go through the Balancing Authority Area checkout process, sending these Dispatch Instructions to ADS is not sufficient. The Dispatch is confirmed by the CAISO Operators and is entered into CAS. In this case the resulting dispatch may be different from the RTM Dispatch instruction. The confirmed Dispatch is communicated back from CAS to the RTM to be used in the next Dispatch calculation. In

other words, CAS overrides ADS once the Dispatch has been entered into CAS and communicated back to RTM.

The actual intertie flows, obtained from telemetry, do not provide information about individual System Resource Dispatch; this information is obtained from CAS. Any difference between the net CAS Dispatch and the telemetered actual flow on a given intertie is attributed to Loop Flow and is factored into the calculation of Loop Flow compensating injections prior to the optimal Dispatch calculation.

7.5.1.2 Self-Schedules in HASP

This section is based on CAISO Tariff Section 34.2.2, Treatment of Self-Schedules in HASP.

SCs may submit Self-Schedules for Supply of Energy to HASP. SCs may not submit Self-Schedules for CAISO Demand to HASP.

The HASP optimization clears Bids, including Self-Schedules, from Non-Dynamic System Resources that submit block Bids and from PDRs that have registered for the 60-minute bid dispatchable option and have bid into the RTM while preserving all priorities in this process consistent with Section 31.4 of the CAISO Tariff. The HASP optimization does not adjust submitted Self-Schedules unless it is not possible to balance Supply and the CAISO Forecast of CAISO Demand plus Export Bids and manage Congestion using the available Effective Economic Bids, in which case the HASP performs adjustments to Non-priced Quantities.

CAISO uses the CAISO Forecast of CAISO Demand and distributes this Demand Forecast based on the applicable set of Load Distribution Factors.

The MWh quantities of Self-Scheduled Supply that clear in HASP constitute a feasible Dispatch for the RTM at the time HASP is run, but HASP results do not constitute a final Schedule for resources other than Non-Dynamic System Resources that submit block Bids, or PDRs that have registered for the 60-minute bid dispatchable option and have bid into the RTM, because these resources may be adjusted in the FMM or RTED if necessary to manage Congestion and clear Supply and Demand.

Self-Schedules submitted for resources other than Non-Dynamic System Resources that submit block Bids or PDRs that have registered for the 60-minute bid dispatchable option and have bid into the RTM that clear in HASP are issued HASP Advisory Schedules which are considered as Self-Schedules or Self-Provision in each of the four FMM intervals. Scheduling Coordinators representing VER resources may submit Self-Schedules in HASP based on the most current Energy forecast based on CAISO's or their own submitted forecast, depending on their election as recorded in the Master File. The HASP produces HASP Advisory Schedules for each of the

four fifteen-minute intervals for FMM Economic Bids cleared in HASP, which can vary from the schedules cleared in the Fifteen Minute Market.

7.5.2 HASP Constraints & Objectives

This section is based on CAISO Tariff Section 34.2.1, The HASP Optimization.

After the HASP and RTM Market Close for the relevant Trading Hour, and the Bids have been validated the HASP optimization determines feasible HASP Advisory Schedules and Ancillary Service awards for most resources for each 15-minute interval of the Trading Hour, as well as hourly HASP Block Intertie Schedules, including binding energy and AS awards, from Non-Dynamic System Resources that submit hourly block Bids for that Trading Hour and binding energy awards for PDRs that have registered for the 60-minute bid dispatchable option and have bid into the RTM for that Trading Hour. For these bids, the optimization produces a set of constant schedules for the four 15-minute intervals of the Trading Hour, honoring system conditions and economic results over the hour.

HASP, like the other runs of RTUC, utilizes the same SCUC optimization and FNM as IFM, with FNM updated to reflect changes in system conditions as appropriate, to ensure that HASP Block Intertie Schedules and 60-minute dispatchable PDR awards are feasible.

Instead of clearing against Demand Bids as in IFM, HASP clears Supply against the CAISO Forecast of CAISO Demand plus submitted Export Bids to the extent the Export Bids are selected in the MPM process. The HASP optimization also factors in forecasted unscheduled flow at the Scheduling Points. Note, self-schedules for export Resources will be given the same scheduling priority as internal price taker demand when validated to be supported by non-RA capacity, and will be given a lower price taker priority when supported by RA capacity. The HASP optimization does not produce Settlement prices for Energy or Ancillary Services.

7.5.3 HASP Outputs

HASP outputs are described in the following subsections.

7.5.3.1 HASP Prices

This section is based on CAISO Tariff Section 34.2.1, The HASP Optimization.

HASP produces advisory 15-minute LMPs for the four 15-minute intervals for the applicable Trading Hour. The HASP optimization does not produce Settlement prices for Energy or Ancillary Services. Bids accepted through the HASP are settled based on FMM Schedules and Awards and FMM LMPs and ASMPs.

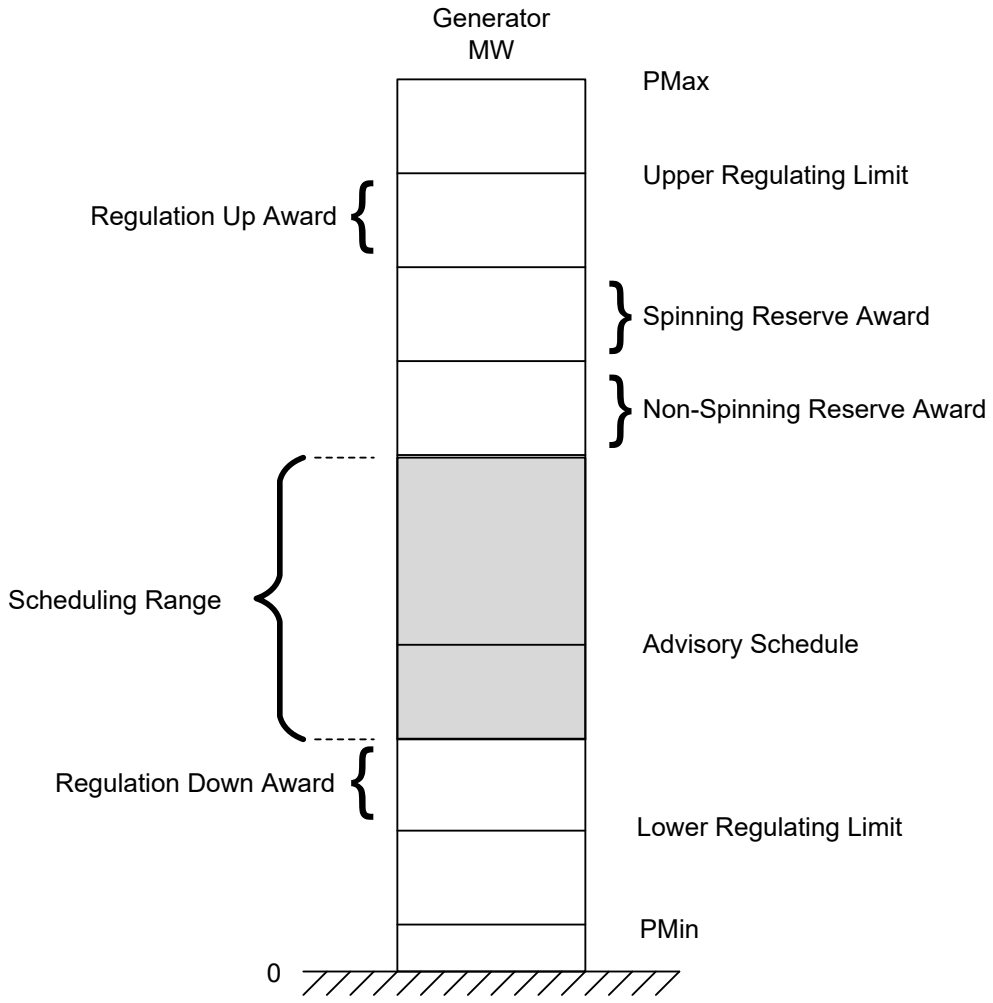
7.5.3.2 HASP Binding Schedules

HASP produces binding Energy and Ancillary Services schedules only for Non-Dynamic System Resources that submit hourly block Bids for the Trading Hour. These schedules are known as HASP Block Intertie Schedules. The HASP also issues binding hourly instructions for PDRs that have registered for the 60-minute bid dispatchable option and have submitted bids into the RTM for the Trading Hour. Although operationally binding, the awarded Energy and Ancillary Services schedules will be settled at prices generated by FMM.

7.5.3.3 HASP Advisory Schedules

Exhibit 7-4 illustrates the advisory Schedule for a Generating Unit for a particular time increment of the HASP. Note: the Energy Schedules for Generating Units (other than PDRs that have registered in the Master File for the 60-minute bid dispatchable option which receives a binding schedule in HASP or 15-minute bid dispatchable option which receives a binding schedule in FMM) and Dynamic Resources are advisory for all intervals in the HASP run, as well as for all intervals of the other three runs of FMM. The Ancillary Services Award for Generating Units and Dynamic Resources is advisory for all intervals but the first interval in all RTUC runs, including HASP.

Exhibit 7-4: Advisory Schedule from HASP



7.6 Real-Time Unit Commitment and Fifteen-Minute Market

This section is based on CAISO Tariff Section 34.3, Real-Time Unit Commitment, and 34.4, Fifteen Minute Market4.

The RTUC process uses SCUC and is run every 15 minutes to:

- Make commitment decisions for Short Start Units that are able to start within the Time Horizon of the RTUC process. For Multi-Stage Generating Resources, it also includes the transition decisions for the Multi-Stage Generating Resources that are able to start within the Time Horizon of the RTUC process

- Determine financially binding FMM Schedules and corresponding LMPs, including System Resources
- Determine operationally binding FMM Schedules for PDRs or PDR-LSRs which have registered for the 15-minute bid dispatchable option in the Master File
- Procure required additional AS and re-calculate ASMP used for settling procured AS capacity for the next 15-minute Real-Time AS interval
- Determine LAP LMPs for use in settling Demand
- Process forecasts and limits for VERs

RTUC is run four times an hour (see Exhibit 7-1), at the following times for the following Time Horizons:

1) Starting at approximately 71.5 minutes prior to the Trading Hour for TH-30 minutes to TH+60 minutes; this includes the HASP run
2) Starting at approximately 52.5 minutes prior to the Trading Hour for TH-15 minutes to TH+240 minutes; this is the STUC run
3) Starting at approximately 37.5 minutes prior to the Trading Hour for TH minutes to TH+60 minutes
4) Starting at approximately 22.5 minutes prior to the Trading Hour for TH+15 to TH+60 minutes

Where TH is the beginning of the Trading Hour.

7.6.1 Real-Time Unit Commitment Inputs

There are no special inputs to the RTUC beyond those described previously from the close of the Real-Time Market at 75 minutes before the start of the Trading Hour.

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 Payments for RUC Awards, i.e., RUC 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.

7.6.2.1 Real-Time Ancillary Services Procurement in HASP

The HASP optimization will consider the optimal mix of Ancillary Services and Energy from System Resources and from Generating Units, but only the Ancillary Service from Non-Dynamic System Resources with hourly block Bids awarded in HASP are binding. These binding Ancillary Services Awards are for the full Trading Hour for which the given HASP run applies. All other resources designated in the HASP to provide Ancillary Services for the same Trading Hour receive non-binding advisory Ancillary Services awards because the CAISO will re-optimize the use of these resources to provide Ancillary Services in the FMM.

All Operating Reserves procured in HASP are Contingency Only Operating Reserves. Scheduling Coordinators submitting Ancillary Services Bids for Non-Dynamic System Resources in the HASP must also submit an Energy Bid under the same Resource ID for the associated Ancillary Services Bid. For these Non-Dynamic System Resources, the CAISO will only use the Ancillary Services Bid in the HASP optimization and will not Schedule Energy in HASP in addition to the relevant Day-Ahead Schedule or Real-Time self-schedule from the Energy Bid provided under the same Resource ID as the Ancillary Services Bid.

7.6.3 Real-Time Unit Commitment Constraints & Objectives

The RTUC uses the SCUC co-optimization engine to minimize costs as reflected in the Bids subject to capacity and inter-temporal resource constraints and using the FNM.

7.6.3.1 Treatment of Generating Resources

Generating Resources that have economic bids will be economically dispatched by the optimization engine and the resulting dispatch is binding in FMM. If the resource is a VER, then for each 15-minute interval an upper dispatch limit will be set to the average of the VER's three forecasts for the corresponding 5-minute intervals. Effectively this means that a VER's bids will be limited or extended to a dynamic upper dispatch limit for each 15-minute interval in the time horizon.

For self-scheduled VERs, FMM calculates a self-schedule for each 15-minute interval in the time horizon by taking an average of the three forecasts for the corresponding 5-minute

intervals (or latest State Estimator reading if forecast unavailable). The resulting set of self-schedules is treated like any other self-scheduled resource.

The RTUC dispatches will be settled at the FMM price. However the dispatch will be subject to further modification in RTD.

7.6.3.2 Treatment of System Resources

System Resource bids have several options of bidding in Real-Time. FMM optimizes these resources differently depending on the bidding option chosen. Treatment of Energy and Ancillary Services is the same.

- Self-Scheduled Hourly Block – Resource dispatch from HASP will be treated as a self-schedule (or Ancillary Services Self-Provision) and will be treated like any other self-scheduled resource. Variable Energy Resource Self-Schedule – Each VER resource has a series of 5-minute forecasts of output. FMM calculates a self-schedule for each 15-minute interval in the time horizon by taking an average of the three forecasts for the corresponding 5-minute intervals (or latest State Estimator reading if forecast unavailable). The resulting set of self-schedules is treated like any other self-scheduled resource.
- Economic Hourly Block Bid – Resource dispatch from HASP will be treated as a self-schedule (or Ancillary Services Self-Provision) and will be treated like any other self-scheduled resource.
- Economic Hourly Block Bid with Intra-Hour Option – Resource dispatch from HASP will initially be treated by FMM as an advisory schedule, i.e. the resource may be economically dispatched by the optimization engine and the resulting dispatch is binding, with the caveat that the resource dispatch must be economic for the binding and any remaining advisory intervals of the Trading Hour, i.e. as if they were constant schedules similar to HASP. If the resulting dispatch is different than the HASP dispatch, then for any subsequent FMM runs in the Trading Hour the previous FMM dispatch will be treated as a self-schedule and will be treated like any other self-scheduled resource.
- Economic Bid for a Schedule in the RTM – The resource may be economically dispatched by the optimization engine and the resulting dispatch is binding. If the resource is a VER, then for each 15-minute interval an upper dispatch limit will be set to the average of the VER's three forecasts for the corresponding 5-minute intervals.
- Dynamic transfer - The resource is treated the same as a Generating Resource by FMM.

7.6.3.3 Treatment of Proxy Demand Resources

FMM optimizes Proxy Demand Resources (PDRs) and Proxy Demand Resource-Load Shift Resources (PDR-LSRs) differently depending on the bid dispatchable option they registered for in the Master File.

- 60-Minute – Resource dispatchable from HASP will be treated as a self-schedule in FMM and treated like any other self-scheduled resource. PDR-LSR is not eligible for the 60-minute bid dispatchable option.
- 15-Minute – the FMM optimization engine may economically dispatch the resource and the resulting dispatch is binding.
- 5-Minute - The resource is treated the same as a Generating Resource by FMM.

7.6.4 Real-Time Unit Commitment Outputs

The resulting RTUC-based commitment instructions are the final decisions regarding resource commitments to adjust Day-Ahead Schedules. Other information is also published. Both the binding awards and information from the first interval and the advisory results from the remaining intervals in the FMM time horizon are available to SCs.

- **Ancillary Service Awards** – generated by FMM and as modified by the CAISO Operator are sent to ADS and CMRI every fifteen minutes for dispatchable resources. The AS Award separately identifies the Day-Ahead Award, the Real-Time qualified self-provision, and the Real-Time AS Award. For Spinning and Non-Spinning Reserve, the Contingency Dispatch indicator is also reported. In any given interval where the software solution does not converge, the CAISO will issue binding Ancillary Services Awards and advisory data based on the advisory results produced by the previous successful RTUC run for the applicable interval. In such cases, all 15-minute data including Ancillary Services Awards, prices, and other supporting data are copied from the advisory results of the previous run.

- **Energy Schedules** – generated by FMM and as modified by the CAISO Operator are sent to ADS and CMRI every fifteen minutes for both binding and advisory intervals. In any given interval where the software solution does not converge, the CAISO will issue energy schedules based on the advisory results produced by the previous successful FMM run for the applicable interval. In such cases, all 15-minute data including Energy Schedules, prices, and other supporting data are copied from the advisory results of the previous run.

- **Commitment Instructions** – generated by RTUC and as modified by the CAISO Operator are sent to ADS every fifteen minutes from RTUC. In any given interval where

the software solution does not converge, the CAISO will issue binding commitment instructions based on advisory commitment instructions obtained from the previous successful RTUC run, if the previous advisory instructions become binding in the current time frame based on the associated startup time, shutdown time or transition times as further described in Tariff Section 34.4 and 34.5. When determined binding, the commitment instructions and all information associated with those instructions of the previous run are copied and carried over into the current run horizon.

- **VER forecast** – The 15-minute resource specific forecast used in FMM will be reported to SCs.

7.6.5 Real-Time Unit Commitment Pricing

The RTUC includes a pricing run to calculate FMM LMPs and ASMPs. FMM produces 15-minute LMPs for the settlement of Supply and Demand. FMM Schedules are settled in accordance with Tariff Section 11.5.

FMM also produces 15-minute ASMPs for any Operating Reserves Awarded in FMM. These ASMPs will correspond to the Ancillary Services Awards procured for the applicable FMM interval.

Both the financially binding prices from the first interval and the advisory prices from the remaining intervals in the FMM time horizon are published.

7.7 Short-Term Unit Commitment

This section is based on CAISO Tariff Section 34.6, Short-Term Unit Commitment.

At the top of each Trading Hour, immediately after the FMM and the RTUC for the same interval is completed, CAISO performs an approximately five-hour STUC run using SCUC and the CAISO Forecast of CAISO Demand to commit Short Start Units with Start-Up Times greater than the Time Horizon covered by the FMM.

The Time Horizon (see Exhibit 7-1) for the STUC optimization run extends three hours beyond the Trading Hour for which the FMM optimization was run, and replicates the Bids used in that Trading Hour for these additional hours.

CAISO replicates Bids each time the hourly STUC is run by utilizing: (1) bids previously submitted in RTM by Scheduling Coordinator for that Trading Hour; or (2) the clean bid from the

DAM if the resource has a Day-Ahead schedule or received a start-up instruction in RUC for the trading hour, or if the resource has a Real-Time must offer obligation for that trading hour. A Start-Up Instruction produced by STUC is considered binding if the resource could not achieve the target Start-Up Time (as determined in the current STUC run) in a subsequent RTUC run as a result of the Start-Up Time of the resource.

A Start-Up Instruction produced by STUC is considered advisory if it is not binding, i.e., when the resource can achieve its target Start-Up Time (as determined in the current STUC run) in a subsequent RTUC run based on its Start-Up Time. A Start-Up Instruction produced by STUC that results in a change in Commitment Status is issued after review and acceptance of the Start-Up Instruction by the CAISO Operator, in accordance with Section 6.3 of the CAISO Tariff.

The STUC only de-commits a resource to the extent that resource's physical characteristics allow it to be brought back online at the end of the Time Horizon. This requirement is needed because RTUC is unaware of future commitments that a resource may have beyond the Time Horizon.

STUC does not produce prices for Settlement. The STUC process only commits units needed for meeting Real Time imbalances. To the extent a unit is committed via STUC, a Start-Up instruction is provided to that resource (via ADS). Whether or not the resource is eligible for Start Up and Minimum Load Bid Cost Recovery is determined through a series of calculations described in the *BPM for Settlement and Billing, Section 12*.

7.7.1 Short-Term Unit Commitment Inputs

The following are special inputs to STUC that are in addition to the common inputs described earlier in this BPM:

- The STUC uses a short-term Load forecast (15-minute intervals over a five-hour Time Horizon

7.7.2 Short-Term Unit Commitment Constraints & Objectives

The STUC application uses the SCUC engine, Market Optimization. STUC enforces the same constraints that are present in all RTUC runs.

The STUC produces a Unit Commitment solution for every 15-minute interval within the Time Horizon.

7.7.3 Short-Term Unit Commitment Outputs

As described in CAISO Tariff Section 34.6, The STUC outputs include the following instructions:

- **Binding Commitment Instructions** – Determined by RTUC, including STUC, are sent to ADS every fifteen minutes.

7.8 Real-Time Economic Dispatch

This section is based on CAISO Tariff Section 34.3.1, Real-Time Economic Dispatch, Section 34.5, General Dispatch Principles, and 34.16.3.1, Regulation.

The RTED mode of operation normally runs every 5 minutes starting at approximately 7.5 minutes prior to the start of the next Dispatch Interval and produces a Dispatch Instruction for Energy for the next Dispatch Interval and advisory Dispatch Instructions for as many as 12 future Dispatch Intervals over the RTD optimization Time-Horizon of up to 65 minutes.

After being reviewed by the CAISO Operator for correctness and reliability,[45] Dispatch Instructions are communicated for the next Dispatch Interval in accordance with Section 6.3 of the CAISO Tariff. RTED produces a Dispatch Interval LMP for each PNode for the Dispatch Interval associated with the Dispatch Instructions.

The objective of RTM is system balancing and Load following above and beyond the normal function of the AGC. AGC is mainly a control tool rather than an Energy service. As AGC units respond to frequency and net Interchange deviations, they temporarily supply or consume balancing Energy, thus moving away from their Preferred Operating Point (POP). The CAISO balances the Energy needs of on a 5-minute interval basis using resources that participate in the RTM which allows the CAISO to move AGC units closer to their POPs.

Resource schedule deviations are classified into instructed and uninstructed. Instructed deviations are the result of participating resources responding to Dispatch Instructions. Uninstructed deviations are the result of Load forecast errors (i.e., a Load resource that varies from its schedule), Forced Outages and contingencies, strategic behavior, modeling limitations, failure to follow Dispatch Instructions, etc. Instructed deviations are price setters, whereas Uninstructed Deviations are Price Takers and may be subjected to penalties. Uninstructed deviations prompt the response of AGC to balance the system. The Dispatch Instructions for subsequent Dispatch Intervals then take as a point of reference the actual output obtained from

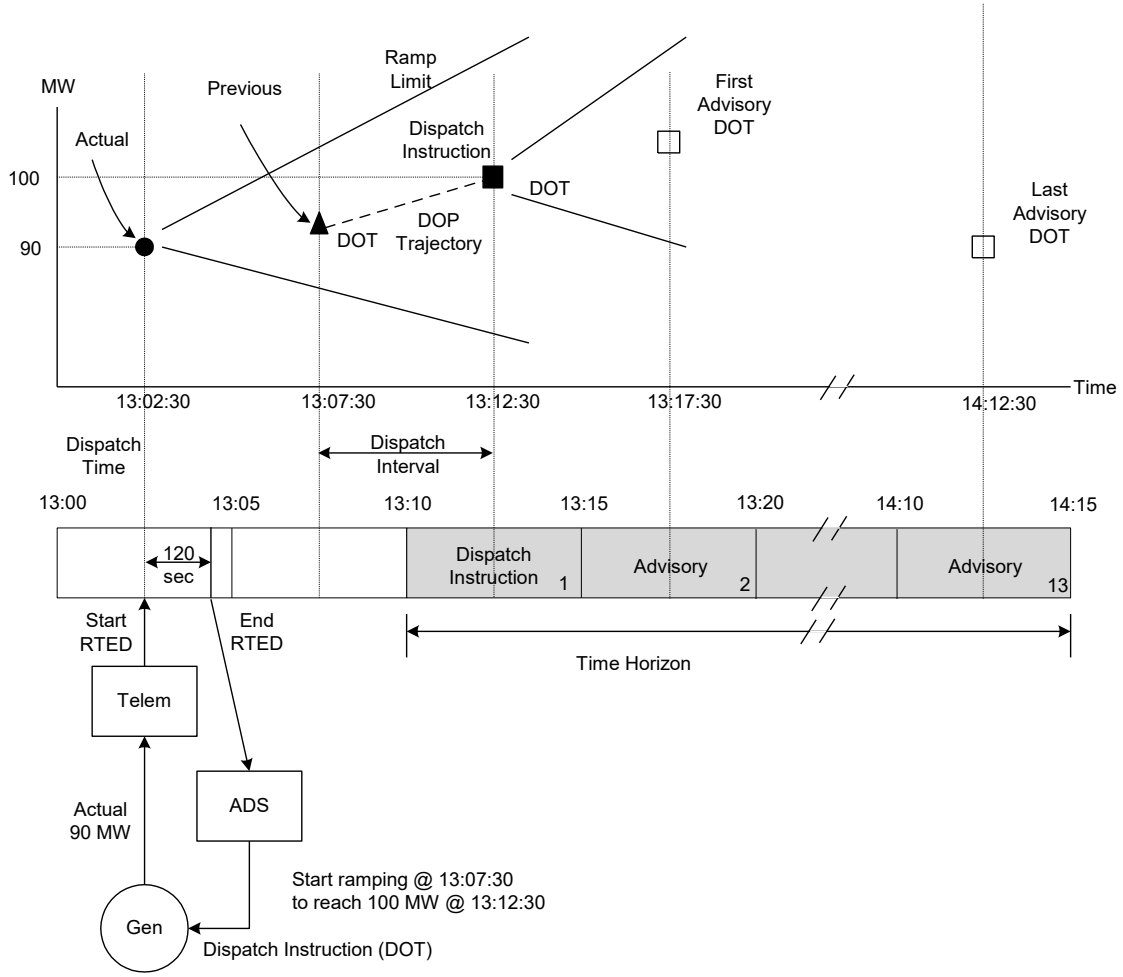
[45] CAISO verifies that the total incremental amount matches what is needed by the Generation dispatch desk, also verifies that resources that were subject to an outage are not part of the dispatch.

either the State Estimator solution or the last valid telemetry measurement. The Dispatch Instructions for each run of the RTED or RTCD meet the projected Energy requirements over the Time Horizon of that run, subject to transmission and resource operational constraints, taking into account the short term CAISO Forecast of CAISO Demand, adjusted as necessary to reflect scheduled changes to Interchange and non-Dispatchable resources in subsequent Dispatch Intervals. In the event of an unscheduled increase in system Demand or a shortfall in Generation output and Regulation margin drop, the CAISO will dispatch Energy or Operating Reserve in the RTM, to restore Regulation margin.

The Dispatch of the selected resources by RTED should result in a feasible outcome, i.e., no resource, network, or security constraints should be violated. Furthermore, if there are any such violations due to system condition changes, resources should be re-dispatched to remove these violations even if there is no system imbalance.

Exhibit 7-5 shows the timeline for RTED, the linkage to ADS, and the corresponding MW versus time graph. The purpose of this timeline is to define the various elements in the Dispatch process – from telemetry input to Dispatch Instruction output.

Exhibit 7-5: RTED Timeline



7.8.1 Real-Time Economic Dispatch Inputs

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

- Real-Time information from the EMS

7.8.1.1 Real-Time Economic Dispatch Initialization

The RTM applications employ a FNM and enforce all network constraints calculating an LMP at each PNode. In this model, the optimal Dispatch must be accurate and realistic at the resource level. The Dispatch approach is to initialize the optimal Dispatch of each participating resource at a calculated operating point obtained from the current SE solution, or optionally the telemetry (when available and reliable), considering the applicable Ramp Rate and capacity limits. This

calculated operating point is derived as a 5-minute extrapolation of the SE solution (or telemetry) towards the last issued DOT. When the SE solution or the telemetry is bad or unavailable, the last DOT can be used for initialization.

The advantage of this dispatch approach is that Uninstructed Deviations are taken into account in the calculation of the optimal Dispatch so that Dispatch Instructions are always feasible at the resource level.

RTED does not run a power flow in itself. The Full Network Model attributes i.e shift factors and loss factors to be used in RTED are based on the last network model information update from FMM. RTED runs a power flow in itself and uses updated FNM information if triggered event i.e. topology change information is provided by the SE solution.

7.8.1.2 Dispatch of Resources that have not submitted RTM bid but have telemetry value

If there is no Energy Bid or a Self-Schedule for a dispatchable Generating Unit or Dynamic System Resource, but the resource is on-line and there is a positive telemetry for that resource, RTED will treat this resource internally as fixed at its telemetry value and will send a zero DOT for that resource through ADS. RTED will continue dispatching the resource in this manner until the resource shuts down, or a scheduled start-up is reached, after which an Energy Bid or a Self-Schedule is available for that resource so that RTED can dispatch it optimally. This does not apply to PDR or PDR-LSRs. If a PDR or PDR-LSR resource does not have a bid, it will be considered as offline.

7.8.1.3 Automated Load Forecasting System (ALFS)

The automated load forecasting System (ALFS) is an application based on advanced neural network and regression models that is designed to capture linear and non-linear interactions between load, weather and calendar information. It uses five-minute averages of actual Load from the Energy Management System for the last 3 years as input for training the neural network. ALFS can generate a forecast for different time intervals and time horizon. CAISO currently uses ALFS to generate a load forecast for the Real-Time market horizon.

The load forecast for any particular day is generated at both system and regional level. The CAISO load forecast includes forecasts for service areas like PG&E, SCE, SDGE, VEA and MWD. PG&E service area has PGE Bay Area, PGE Non-bay Area, and San Francisco sub-regions modeled. SCE service area has SCE Inland and SCE Coastal sub-regions modeled. Forecasts at the MSS levels (NCPA, SVP, Anaheim, Riverside and Vernon) are also calculated. The CAISO operator has the option to make manual adjustments to the forecast generated by ALFS for use in the Real-Time Market.

ALFS produces a load forecast for each five-minute Dispatch Interval in the Real-Time Market time horizon. The forecast models use the latest weather forecast available from weather providers in addition to other inputs such as actual load for the real-time forecasts. The load forecast for 15-minute intervals is derived as the average of three relevant five-minute Dispatch Intervals. The CAISO has developed multiple models for Real-Time that generate a forecast every 5 minutes. The CAISO operator has the ability to view and use the assortment of forecasts or the load curve from a similar day or a blend of both in the Real-Time Market.

In addition to weather forecasting, ALFS produces a generation forecast for VER resources based on weather and atmospheric conditions as well as plant information. The forecast is produced for a five-minute Dispatch Interval granularity and is updated every five minutes.

7.8.1.4 Use of internal Dispatch Operating Target

Consistent with general dispatch principles set forth in the CAISO Tariff, the CAISO may calculate a DOT for resources without a forecast or a bid for purposes of its real-time market optimization, i.e. an internal DOT. For example, the CAISO may calculate an internal DOT for EIRs when the EIR has yet to provide the CAISO will sufficient production data and meteorological data for the ISO to develop a forecast for the EIR under Appendix Q of the tariff. The CAISO may also calculate an internal DOT for resources that do not submit a bid into the real-time market. For a solar resource, the internal DOT reflects the resource's current telemetry as well as a curve that captures solar ramp up and ramp down for that interval. For all other fuel types, the internal DOT remains fixed for the entire RTD interval at the resource's current telemetry. The CAISO will use these internal DOTs as inputs to RTED but not to settle resources.

7.8.2 Real-Time Economic Dispatch Constraints & Objectives

The RTD application uses the SCED engine, Security Constrained Economic Dispatch.

RTD will apply the following bid processing for VERs. If the VER has submitted economic Bids, then for each 5-minute interval an upper dispatch limit will be set to the VER's 5-minute persistent forecast as calculated by the SCED for CAISO VER resources. Effectively this means that a VER's bids will be limited or extended to a dynamic upper dispatch limit for each 5-minute interval in the time horizon. For self-scheduled VERs, FMM calculates a self-schedule for each 5-minute interval in the time horizon based on the 5-minute forecast. The resulting set of self-schedules is treated like any other self-scheduled resource.

RTED provides the functionality to classify and prioritize constraints among themselves and the control Dispatch priorities. A common system of priority levels is supported for both resource and Constraint priorities. The priority level for any control or Constraint class is configurable. Control and Constraint classes may share the same priority level.

Initially, all constraints have higher penalty than all resource priorities. The priorities are listed in Section 7.5.1, Hourly Schedule Changes & Dispatch Priorities.

7.8.2.1 Cross-Interval Ramping

The RTM applications calculate the optimal Dispatch to meet the average Demand Forecast in each Dispatch Interval, effectively placing the DOT at the center of the Dispatch Interval. With this calculation, dispatched resources are expected to follow Dispatch Instructions Ramping symmetrically across each Dispatch Interval boundary. A ramp between the centers of consecutive Dispatch Intervals provides the best possible Load following and simplicity since it applies uniformly to all dispatched resources.

This approach was adopted because of its simplicity, transparency, and uniformity, the lower reliance on Regulation, and the beneficial impact in meeting Control Performance Standards (CPS).

7.8.2.2 Imbalance Energy Requirement & Bias

The Imbalance Energy requirement corresponds to the Power balance Constraint in the optimal dispatch formulation. The Imbalance Energy requirement for each time interval in the RTM is calculated as the Load prediction obtained from the VSTLP for that interval, reduced by fixed Supply and the Marginal Losses contribution of participating resources at the base operating point using loss sensitivity factors.

The Marginal Losses contribution of participating (dispatchable) resources must be subtracted because the Load projection includes the system Transmission Losses at the base operating point. The base operating point is a power flow solution obtained at 15-minute intervals from the SCUC solution using a distributed Load slack and is used to linearize the non-linear power flow equations.

The loss sensitivity factors are calculated from sensitivity analysis at that power flow solution with Net Scheduled Interchange (NSI) fixed for each Balancing Area, and thus represent a linear Transmission Loss approximation due to both participating resource and non-Participating Load deviations.

In general, there is no need to reflect Uninstructed Deviations in the Imbalance Energy requirement because the Dispatch is initialized at the previous DOT, which is extrapolated from the State Estimator solution, and thus any Uninstructed Deviations are already accounted for.

However, to account for resources that produce Energy during their startup process, the start-up ramp time parameter will be used to predict the resource's output. This parameter, stored in the Master File, applies to Generating Units generally and MSG Configurations. The start-up ramp time is used by the Day-Ahead Market or Real-Time Market to calculate the linear start-up profile for internal imbalance consideration. In cases where the start-up time is zero minutes, the start-up ramp will be considered to be instantaneous at the time of the startup.

In addition, there may be a need to account for resources that are persistently non-responsive to Dispatch Instructions because such non-responsive resources impact the ability of CAISO to satisfy its Imbalance Energy requirements. These resources are flagged as non-compliant and they are treated as fixed at their SE solution for all intervals of the Time Horizon.

The RTM applications provide an interface to the CAISO Operator to adjust/bias the Imbalance Energy requirements within the relevant Time Horizon to reflect information that is known to the CAISO Operator, but not to the RTM. For example, a pending Outage that is not yet reflected in outage management system, a pending curtailment of a large Load, or an expected large Uninstructed Deviation. The Imbalance Energy bias is used by all RTM applications while in effect.

7.8.2.3 Available Operating Reserve Calculation

SCED calculates the available Operating Reserve for relevant resources in each Dispatch Interval using the applicable Ramp Rate function, the binding DOT, and the Start-Up Time, if applicable. This 10-minute capability, in association with Operating Reserve Dispatch Instructions, is used in the No Pay mechanism to rescind capacity payments for unavailable Operating Reserve.

For example, a resource that at a given DOT has a lower Ramp Rate than was used by Ancillary Service management to procure Operating Reserve; it may be incapable of providing the awarded Operating Reserve in full within the time frame awarded. Another example is a resource that has suffered a partial or full Outage that has reduced its Maximum Operating Limit or its Ramp Rate.

The available Operating Reserve calculation is to be used by the No Pay mechanism (described in more detail in the BPM for Compliance Monitoring) and other CAISO processes.

The available Operating Reserve calculation is performed on all resources that have capacity covered by Bids (whether submitted or inserted) regardless of whether Ancillary Services have been awarded and regardless of the resource's on-line status. This is based on Section 8.10.8 of the CAISO Tariff. Only interties (Non-Dynamic System Resources) are exempted from this requirement.

The available Operating Reserve is calculated for every Generating Resource and Dynamic System Resource with Energy Bids and/or Ancillary Service Awards for a 10 minute period starting at the binding DOT.

The available Operating Reserve for online Generating Resources is calculated using the applicable Operational Ramp Rate function ORR(P), which could be static or dynamic and may reflect applicable ramp rate derates, and it is limited from above by the lower of the applicable Upper Economic Limit (UEL) or Upper Operating Limit (UOL). The UEL is the top of the Energy Bid, whereas the UOL is the registered Generating Resource Maximum Capacity, reduced by any applicable derates. Note that the Upper Regulating Limit (URL) is ignored in this calculation even if the Generating Resource is on Regulation because it is assumed that the resource can be taken off Regulation if that is necessary to dispatch Operating Reserve.

Let $RRU_{\tau}(P)$ be the function that returns the maximum incremental dispatch from P within time τ using ORR(P). Then, the available Operating Reserve (AOR) for online resources is calculated as follows:

$$AOR = \max\left(0, \min\left(RRU_{10'}(DOT), UEL - DOT, UOL - DOT\right)\right)$$

Example:

Pmin = LOL = 50 MW; Pmax = UOL = 200 MW; UEL = 150 MW; DOT = 80 MW.

$$ORR(P) = \begin{cases} 4\,\text{MW/min} & \because \quad 50\,\text{MW} < P < 100\,\text{MW} \\ 5\,\text{MW/min} & \because \quad 100\,\text{MW} < P < 150\,\text{MW} \\ 2\,\text{MW/min} & \because \quad 150\,\text{MW} < P < 200\,\text{MW} \end{cases} \Rightarrow \quad RRU_{10}(DOT) = 45\,\text{MW}$$

Then:

$$AOR = 45\text{MW}$$

The available Operating Reserve for offline Generating Resources with Non-Spinning Reserve Awards is calculated using the applicable Lower Operating Limit (LOL), Start-Up Time SUT(OFF(t)), Off Time OFF(t), and Operational Ramp Rate function ORR(P), which could be static or dynamic and may reflect applicable ramp rate derates, and it is limited from above by the lower of the applicable Upper Economic Limit (UEL) or Upper Operating Limit (UOL). The LOL is the registered Generating Resource Minimum Load, increased by any applicable overrates. The Off Time and SUT are evaluated at the start of the Time Horizon T_r. Then, the AOR is calculated as follows:

$$AOR = \begin{cases} \min\left(LOL + RRU_{10'-SUT\,(OFF\,(T_r))}(LOL), UEL, UOL\right) & \because \quad SUT\left(OFF\,(T_r)\right) \le 10' \\ 0 & \because \quad SUT\left(OFF\,(T_r)\right) > 10' \end{cases}$$

Example:

Same example as before, but the unit is now offline at T_r and the DOT is zero with:

$$OFF(T_r) = 50\,\text{min}$$

And:

$$SUT(OFF) = \begin{cases} 7\,\text{min} & \because \quad OFF < 60\,\text{min} \\ 20\,\text{min} & \because \quad 60\,\text{min} \le OFF < 240\,\text{min} \\ 60\,\text{min} & \because \quad 240\,\text{min} \le OFF \end{cases} \quad \Rightarrow \quad SUT(T_r) = 7\,\text{min}$$

Then:

$$RRU_{3'}(LOL) = 12\,\text{MW}$$

Thus:

$$AOR = 50 + 12 = 62\,\text{MW}$$

Note that if there is no Energy Bid, the UEL is equal to the Total Self-Schedule, and if there is no Self-Schedule it defaults to the LOL.

If RTM fails, or it is skipped either because of manual intervention or because of switching to RTCD that has a 10-min time horizon, there may be a Dispatch Interval without available Operating Reserve. For RTM failures or a Dispatch Interval without available Operating Reserve, the No Pay mechanism will set the available Operating Reserve to an extremely high value, 999 MW, such that all Operating Reserve is available in that Dispatch Interval.

7.8.2.4 Forbidden Operating Regions

Forbidden Operating Regions (FORs) are distinct non-overlapping operating regions within which Generating Units cannot operate stably. A Generating Unit may be scheduled or Dispatched within an FOR in an interval only if it takes longer than the duration of the interval to cross that region. In such case, the Generating Unit must be scheduled or Dispatched in subsequent intervals in the same direction (up or down) so that it clears the FOR in the least number of intervals possible. Depending on its Crossing Time, a resource may be dispatched to the boundary of its FOR before proceeding to cross the FOR in subsequent interval(s).

FORs are static and defined in the Master File along with all other resource characteristics. There is support for up to four FORs for a given Generating Unit, however, not all resources have FORs. The market applications obtain the static FOR definition directly from the Master File along with all other resource characteristics. The Operational Ramp Rate Bid is currently limited by SIBR validation to four segments without regard to FORs.

The Forbidden Operating Region Ramp Rates, are static and are included in the FOR definition in the Master File, albeit not as Ramp Rates, but as Crossing Times; an average Ramp Rate can be derived by dividing the range of the FOR with its Crossing Time.

If there are registered FORs for the Generating Unit and the Bid period specified in the Bid, the Operational Ramp Rate curve specified in the Generating Unit Operational Ramp Rate Bid component is modified so that the operating range covering each FOR has an operational ramp rate equal to the ratio of the FOR range over the corresponding registered Crossing Time, subject to the 10:1 rule specified in section 6.6.2 of this BPM.

In the Real-Time Market, the above Forbidden Operating Region rules apply in conjunction with the rules for application of Self-Schedules and Economic Bids submitted by the Scheduling Coordinator, as further described below.

- In the event that a Scheduling Coordinator submits a Self-Schedule within a Forbidden Operating Region, the CAISO will honor the Self-Schedule and the Forbidden Operating Region will not be observed. In this instance the unit's dispatch is driven by Self-Schedule and the CAISO Market solution will drive the unit as instructed by the Self-Schedule to the Self-Scheduled MW value.

- The Dispatch for the Generating Unit is fixed at its telemetry MW value if Generating Unit's effective Energy economic range [Pmin, Pmax] lies completely within the Forbidden Operating Region because of either: 1) the Bids submitted by the Scheduling Coordinator; or 2) conditions such as MSS load following up, MSS load following down, Ancillary Services, de-rate or rerate conditions, etc. ,, .

- In the Real-Time Dispatch only, if the resource only has Self-Schedules (without Economic Bids) for sequential hours and is crossing the Forbidden Operating Region between the Self-Schedules, then the Forbidden Operating Region implicit ramp rate is ignored and the 20 minute Self-Schedule ramping rule will be used as described in section 7.6.3.1 of this BPM.

It should be noted that the Forbidden Operating Region rules will prevail in other cases, including where the resource has Self-Schedules with Economic Bids and is crossing the Forbidden Operating Region between the Self-Schedules. There will be times when the next hours Self-Schedule appears in the time horizon and the Generating Unit is already crossing the Forbidden Operation Region in a direction away from that Self-Schedule. In these cases the Dispatch will continue to honor the Forbidden Operation Region rules, crossing through the Forbidden Operating Region until the boundary is reached, and as required crosses back towards the next hour's Self-Schedule. Depending on the crossing time, the Generating Unit may not reach its Self-Schedule value until well after the beginning of the hour.

7.8.2.5 Stored Energy Management for Non Generator Resources in Real-Time

For NGRs designated as Limited Energy Storage Resources (LESRs), state of charge (SOC) constraints are applied to both the binding and non-binding intervals in FMM and RTD based on their Master File parameters, Lower and Upper Charge Limit bids, End-of-Hour (EOH) SOC bids limits, and, if applicable, the reliability-induced Minimum SOC described in section 2.5.8 of this BPM.

Real-Time Interval State-of-Charge Management

To model state of charge for storage resources during each interval the real-time market uses telemetered values for state of charge from storage resources to calculate an initial value, similar to the way initial operating levels are calculated for traditional generation. From these initial conditions state of charge is updated from energy and regulation awards throughout the look-ahead periods considered by the real-time market. This is a similar process to how state of charge is modeled in the day-ahead market, outlined in section 6.6.2.3, with the exception that the real-time interval state of charge considers the impacts of Uncertainty Awards in the upward direction. As a result, the state of charge is calculated for each interval in real-time markets as follows:

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

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

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

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

$$0 \leq EN_{i,t}^{(+)} \leq u_{i,t} UEL'_{i,t}$$

$$(1 - u_{i,t}) LEL'_{i,t} \leq EN_{i,t}^{(-)} \leq 0$$

$$EN_{i,t,} = EN_{i,t}^{(+)} + EN_{i,t}^{(-)}$$

$$u_{i,t} = \{0,1\}$$

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 of the Market Operations BPM.

Please reference Section 4.2.9 of the Market Operations BPM for the ancillary service award constraint impacts on state of charge.

Then, the ancillary service awards are constrained as follows:

$$\underline{SOC_{i,t}} + (SR_{i,t} + RU_{i,t} + NR_{i,t}) \frac{30'}{T} + FRU_{i,t-1} \frac{\Delta T}{T} \leq SOC_{i,t} \leq \overline{SOC}_{i,t} - \eta_i RD_{i,t} \frac{30'}{T} - \eta_i FRD_{i,t-1} \frac{\Delta T}{T}$$

In RTD, the SOC remaining at the end of the RTD time horizon is constrained to ensure the LESR is able to meet its self-schedules in intervals beyond the scope of the RTD time horizon. The end of horizon SOC will be constrained in RTD as follows:

$$SOC_{i,te} \geq \underline{SOC}_{i,te} + \max(0, SSEn_{i,te}, \underline{P}_{i,te} + SSRd_{i,te}) \frac{RM}{T}$$

$$SOC_{i,te} \leq \overline{SOC}_{i,te} + \eta_i \min(0, SSEn_{i,te}, \overline{P}_{i,te} - SSRu_{i,te} - SSSr_{i,te} - SSNr_{i,te}) \frac{RM}{T}$$

Where:

5) i is the resource index;

t is the time interval index;

te is the time interval in which the RTD case ends;

ΔT is the time interval duration (15min in FMM and 5min in RTD);

T is the time unit, 60min;

SOC is the State of Charge;

$\overline{SOC}$ is the maximum State of Charge[46];

$\underline{SOC}$ is the minimum State of Charge[4646];

$P^{(+)}$ is the discharging schedule (positive);

$P^{(-)}$ is the charging schedule (negative);

P is the optimal dispatch (algebraic);

$\overline{P}$ is the maximum discharging capacity (positive);

$\underline{P}$ is the minimum charging capacity (negative);

η is the charging efficiency;

u is the binary mode of operation, 1 for discharging and 0 for charging;

RU is the Regulation Up award;

RD is the Regulation Down award;

SR is the Spinning Reserve award;

NR is the Non-Spinning Reserve award;

FRU is the Flex Ramp Up award;

FRD is the Flex Ramp Down award;

$SSEn$ is the Self-Scheduled Energy;

$SSRd$ is the Self-Scheduled Regulation Down;

$SSRu$ is the Self-Scheduled Regulation Up;

$SSSr$ is the Self-Scheduled Spinning Reserve;

$SSNr$ is the Self-Scheduled Non-Spinning Reserve; and

Formatte
Reference

[46] The minimum and maximum State of Charge (SOC) enforced in the market will depend on the resource's Master File parameters, bids, and system conditions as described in section 2.8.5.2 of this BPM.

RM	is the number of minutes remaining from the end of the RTD case to the start of the next hour.

CAISO tariff section 8.3.4 requires that resources scheduled to provide Spinning Reserve and Non-Spinning Reserve must be capable of maintaining that output or scheduled Interchange for at least 30 minutes from the point at which the resource reaches its award capacity. Resources offering Regulation in the real-time market must also have the capability to meet a continuous energy requirement for at least 30 minutes. *See* CASIO tariff section 8.4.1.1 and Appendix K, Part A.

Consistent with these requirements, when an NGR receives a Spinning Reserve or Non-Spinning reserve award, the CAISO will reserve its SOC to ensure the NGR can continuously deliver that capacity for 30 minutes. When an NGR receives a Regulation award or qualified self-provision, the CAISO will reserve its SOC to ensure it can continuously deliver that capacity for 30 minutes in the applicable fifteen-minute market and RTD interval.

Energy schedules and ancillary service awards are co-optimized in FMM subject to these SOC constraints. The ancillary service awards are fixed in RTD; however, the SOC constraints are still enforced in RTD to constrain the energy dispatch so that the sustained energy requirement is satisfied, and to ensure future awards and self-schedules can be met.

In Real-Time Contingency Dispatch (RTCD) and in Real-Time Disturbance Dispatch (RTDD) the market application will release the state of charge to deliver Spin and Non-Spin capacity for 10 minutes but continue to reserve the state of charge to ensure deliverability of Spin and Non-Spin capacity for future RTCD and RTDD. In subsequent RTCD and RTDD market runs, the application will release all state of charge to deliver Spin and Non-Spin capacity. In all RTCD and RTDD market runs, the market application will reserve the state of charge for 30 minutes to support deliverability of Regulation Up and Regulation Down capacity. In the event that a specific resource does not have sufficient state of charge prior to an ancillary service award or qualified self-provision in any fifteen-minute market interval, the CAISO may procure incremental ancillary services from another resource. In this event, the resource with an insufficient state of charge will be subject to the CAISO's payment rescission rules.

For NGRs using Regulation Energy Management functionality, SOC is maintained by automatic generation control (AGC) with the following 50 percent rule:

- Maintains the SOC at 50% if system conditions are normal and it is not impacting the grid reliability by doing so.
- If SOC is below 50% and the system needs Regulation Down energy, AGC will calculate the MW charge level, and send a set point to NGRs for charging.
- If SOC is above 50% and system needs Regulation Up energy, AGC will calculate the MW charge level, and send a set point to the NGR for discharging.

RTD is mimicking what AGC is doing to bring SOC to 50 percent.

End-of-Hour State-of-Charge Management

Scheduling coordinators for LESRs may submit optional end-of-hour (EOH) state-of-charge (SOC) limits in the real-time market, as part of their energy bids, to manage the optimal use of their resources throughout the day. These EOH SOC limits are different from the minimum and maximum daily SOC limits, which ensure that resources receive dispatches that respect such daily SOC limits at the end of every market interval. Instead, the market may dispatch LESRs to meet imbalance energy needs within the hour, while ensuring the resource's SOC satisfies the EOH limits only at the end of the corresponding hour, if submitted as part of the energy bids.

The scheduling coordinator submits a bid with minimum and maximum EOH SOC limits in MWh to reflect a target range. If the scheduling coordinator desires a single target EOH SOC, then the minimum and maximum EOH SOC limits may be set the same. The real-time market will respect an LESR's minimum and maximum EOH SOC limits. The market will ignore EOH SOC limits if they conflict with the resource's daily minimum and maximum SOC limits. However, there are bid validation rules that limit these occurrences in the market. See the *BPM for Market Instruments,* Appendix Attachment A, for more details.

The market prioritizes respecting ancillary services awards[47] when a scheduling coordinator provides hourly EOH SOC limits that create conflicts. The market will maintain an SOC if the resource is providing ancillary services such that the resource can provide the full awarded MW amount over a 30-minute period. If a scheduling coordinator were to submit an EOH SOC target of 4 MWh, but the resource's ancillary service awards require an 8 MWh SOC to ensure the ancillary service's award can be met, the market will maintain the more limiting 8 MWh SOC. In addition, although the market will attempt to move the resource to the targeted EOH SOC, the actual state of charge could fluctuate above or below targets due to response from ancillary service instructions. Therefore, in hours where the resource receives simultaneous ancillary

[47] However, satisfying the EOH SOC constraint will take precedence over procurement of ancillary services.

service and energy awards, there is no guarantee that the resource's EOH SOC targets will be met. The market also respects Exceptional Dispatch instructions and cannot guarantee EOH SOC targets will be honored when EOH SOC limits and Exceptional Dispatch instructions simultaneously exist in the optimization time horizon.

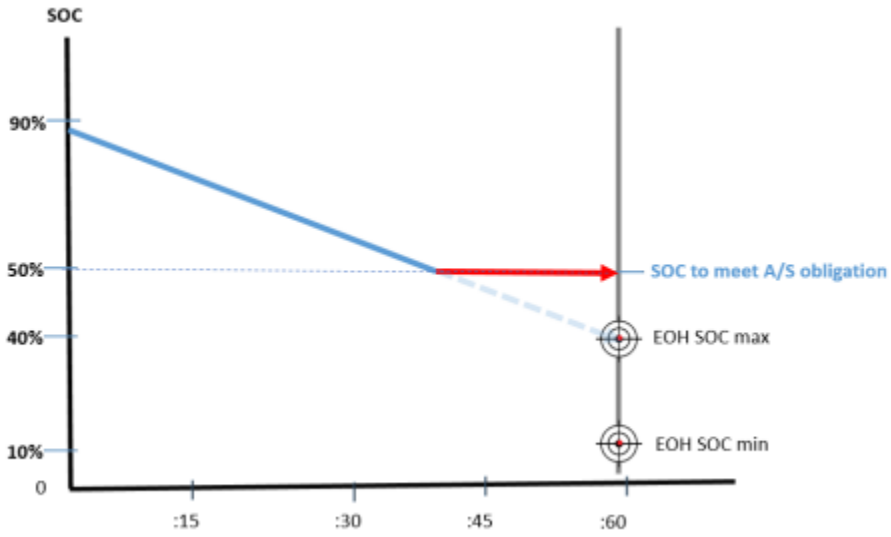


Figure 1: Example of Ancillary Service award impact on an EOH SOC bid

While the Short-term Unit Commitment (STUC) market runs have no influence on energy storage resources, submitted EOH SOC limits can still influence the decision to commit (or not) additional medium-start units. Since real-time bids can be submitted and changed from the close of the day ahead market to 75 minutes prior to the start of the hour, to prevent any potential gaming opportunities, the CAISO will only use the binding limits in STUC, i.e., for hours for which the bidding market has closed.

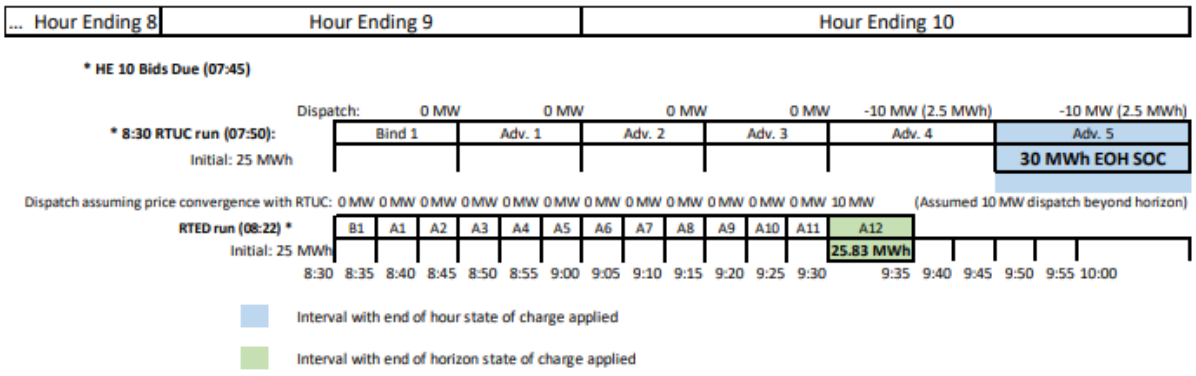
End-of-horizon management in RTED

Although the RTUC time horizon always ends at the end of an hour, the RTED market may not, depending on the interval within the hour. There are several RTED runs that do not consider the same EOH SOC limits that an RTUC does, with the same binding interval start time. Thus, there may be sub-optimal situations where those RTED runs could undo what was planned by the RTUC/FMM, by not dispatching to charge or discharge the resource until it is too late to meet the EOH SOC targets.

End-of-horizon SOC constraints are implemented to align visibility of the EOH SOC limits to the same binding intervals for both RTED and RTUC/FMM. The end-of-horizon SOC constraint will enforce the EOH SOC limits, adjusted for the resource's charging activity for intervals beyond the RTED time horizon until the EOH as determined by the latest RTUC advisory instructions for that period. For the purposes of the following two examples, consider the following: a 40 MWh resource with a -10 MW Pmin and 10 MW Pmax has a 25 MWh (62.5%) initial SOC for the RTUC 08:30 run, and must get to at least 30 MWh by the end of Hour Ending 10, thus an additional 5 MWh of charging is required[48]. In this same example, the initial SOC for the RTED 08:30 run is also 25 MWh. Suppose the resource is not economic to charge in the any of the binding or advisory intervals of the RTUC/FMM and RTED runs.

RTED end of horizon example 1:

For the RTUC, supposed the most economic prices to charge are for the last two intervals of the horizon, namely 09:30-09:45 and 09:45-10:00, so the resource will be scheduled at -10 MW for the 09:30 and 09:45 advisory intervals. When creating an end of horizon SOC constraint for the RTED 08:30 run, for which the horizon ends at 09:35, it is assumed that the RTED results will be following RTUC beyond 09:35. Thus, there will be 4.17 MWh of charging for the intervals covering 09:35-10:00 that are beyond the optimization time horizon[49]. The EOH SOC constraint for RTED thus becomes 30 MWh – 4.17 MWh, or 25.83 MWh of minimum SOC. Assuming prices between RTUC and RTED are converging, the incremental 0.83 MWh of charging will be dispatched in the interval 09:30-09:35.[50]



[48] This requires two 15-minute intervals of full charging (-10 MW * ½ hour = five MWh.)

[49] 10 MW * 25 minutes * (1 hour / 60 minutes) = 4.17 MWh.

[50] -10 MW * 5 minutes * (1 hour / 60 minutes) = 0.83 MWh.

Figure 2: RTED end-of-horizon example 1

RTED end of horizon example 2:

For the RTUC, suppose the most economic prices to meet the target are for the two intervals of the horizon 09:00-09:15 and 09:15-09:30, so the resource will be scheduled at -10 MW for the 09:00 and 09:15 advisory intervals. When creating an end-of-horizon SOC constraint for the RTED 08:30 run, for which the horizon ends at 09:35, it is assumed that the RTED results will follow RTUC. Thus, there will be no charging for the intervals 09:35- 10:00 that are beyond the optimization time horizon. The end of horizon SOC constraint for RTED thus becomes 30 MWh of minimum SOC. Assuming prices between RTUC and RTED are converging, the five MWh of charging will be picked up in the intervals 09:00-09:30[51].

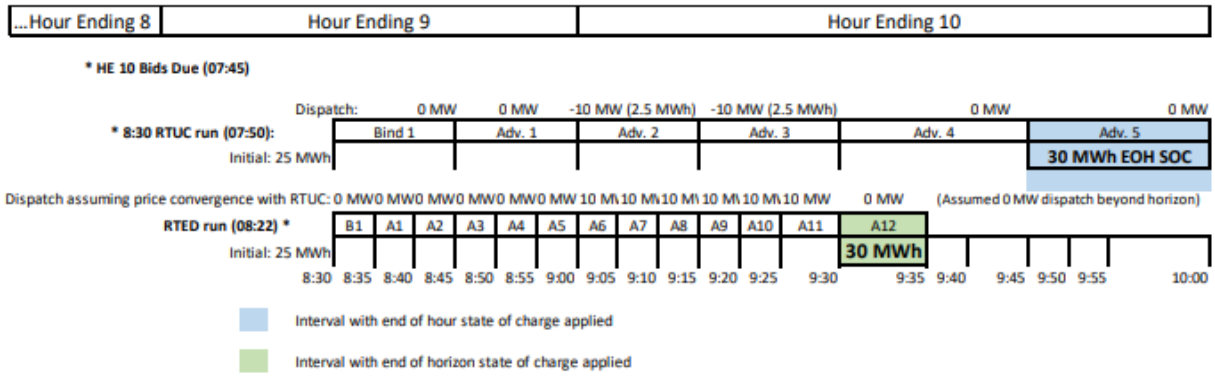


Figure 3: RTED end-of-horizon example 2

Interaction between EOH SOC and MSOC constraints

The Minimum State-of-Charge (MSOC) constraint described in section 2.5.8 of this BPM is a form of EOH SOC constraint. If the MSOC constraint is not active, the minimum and maximum EOH SOC limits submitted as part of bids will be used in the optimization. If MSOC requirements exist and are active, they will take priority over the bid EOH SOC and daily SOC limits during *critical*[52] hours. During non-critical hours, the most restrictive between MSOC,

[51] Although the inputs to both real-time markets are the same, the two markets can lead to different results, and prices may not always converge.

[52] Critical hours are defined by CAISO Operators based on Good Utility Practice. Critical hours are intended to represent the most critical load-serving hours of the day. All other hours of the day are deemed non-critical.

minimum bid EOH SOC, and daily minimum SOC limits will be used. If necessary, the maximum bid EOH SOC and the daily maximum SOC limits shall be set to the MSOCwhen in conflict.

Example-1:

For a given RTM market interval (within critical hours) and a non-REM LESR with the following parameters:

- No Biddable Daily Lower Charge Limit
- No Biddable Daily Upper Charge Limit
- Biddable Min EOH SOC = 30 MWh
- Biddable Max EOH SOC = 70 MWh

If MSOC = 25 MWh, binding EOH SOC constraints used in RTM shall be:

- Min EOH SOC = 25 MWh (from MSOC)
- Max EOH SOC = 70 MWh (from Bid)

If MSOC = 50 MWh, binding EOH SOC constraints used in RTM shall be:

- Min EOH SOC = 50 MWh (from MSOC)
- Max EOH SOC = 70 MWh (from Bid)

If MSOC = 80 MWh, binding EOH SOC constraints used in the RTM shall be:

- Min EOH SOC = 80 MWh (from MSOC)
- Max EOH SOC = 80 MWh (Biddable Max EOH SOC conflicts with MSOC. Max value is set to MSOC)

Example-2:

For a given RTM market interval (within non-critical hours) and a non-REM LESR with the following parameters:

- No Biddable Daily Min ESL
- No Biddable Daily Max ESL
- Biddable Min EOH SOC = 30 MWh
- Biddable Max EOH SOC = 70 MWh

If MSOC = 25 MWh, binding EOH SOC constraints used in the RTM shall be:

- Min EOH SOC = 30 MWh (from Bid)
- Max EOH SOC = 70 MWh (from Bid)

If MSOC = 50 MWh, binding EOH SOC constraints used in the RTM shall be:

- Min EOH SOC = 50 MWh (from MSOC)
- Max EOH SOC = 70 MWh (from Bid)

If MSOC = 80 MWh, binding EOH SOC constraints used in the RTM shall be:

- Min EOH SOC = 80 MWh (from MSOC)
- Max EOH SOC = 80 MWh (Biddable Max EOH SOC conflicts with MSOC. Max value is set to MSOC.)

7.8.3 Real-Time Economic Dispatch Outputs

RTED outputs the following. Both the binding awards and information from the first interval and the advisory results from the remaining intervals in the RTD time horizon are available to SCs.

- **Dispatch Instruction** –DOT (the binding one) as modified by the CAISO Operator is required and is sent to ADS. This instruction includes a breakdown of the DOT into its service components. Note also that no Energy calculation is needed at this step since the breakdown is a MW breakdown of the MW instruction. In any given interval where the software solution does not converge, the CAISO will send binding Dispatch Instructions and advisory results based on advisory results applicable to this interval obtained from the previous successful RTED run. In such cases, all 5-minute data including DOP, DOT, LMP prices and other supporting data is copied from the advisory results of the previous run.

- **Exceptional Dispatches** – Exceptional Dispatches are manually determined but enforced in RTM and sent to ADS when they are issued. Several non-conflicting Exceptional Dispatches may be present for each dispatchable resource in the current and next hour.

- **VER forecast** – The 5-minute resource specific forecast used in RTD will be reported to SCs.

7.8.3.1 Dispatch Operating Target Breakdown

The Dispatch Operating Target or DOT is broken down into various MW service components in ADS.

The DOT breakdown that CAISO provides to market participants through ADS is to illustrate the Energy component of the Dispatch Instructions in terms of MW capacity constituting the total DOT MW. This breakdown is used by the CAISO for operational purposes including but not limited to, compliance checking and available operating reserve calculation. It is also used by market participants for shadow settlement purposes.

Although the DOT breakdown is used to represent Energy components of the Dispatch Instructions, they are calculated and represented in terms of MW capacity and hence they do not represent the energy difference due to ramping between intervals.

There are two types of real-time Dispatch Instructions that CAISO sends out through ADS, i.e., hourly pre-dispatch instruction and real-time dispatch instruction. There are differences in how to interpret and use the DOT breakdown MWs between the two types of instructions.

7.8.3.1.1 DOT Breakdown in Non-Dynamic System Resource Instruction

These instructions apply to Non-Dynamic System Resources dispatched in FMM, including HASP. There are two critical components:

- SCHED: The SCHED MW reflects the final day-ahead energy schedule.
- SUPP: The SUPP MW is the difference between DOT and SCHED. It is effectively the incremental (positive) or decremental (negative) value from the Self-Schedule MW.

Although the standard ramp RMPS is also calculated for the intertie System Resources in the DOT breakdown, the standard ramp has little relevance to the ultimate energy settlement of hourly pre-dispatched system resources since such energy is accounted for on a block basis. There will not be any Spin or Non-spin MWs for hourly pre-dispatched resources since we do not model AS import on the hourly pre-dispatched resources. Note also that there are two scenarios under which the SCHED will be equal to the final Day-Ahead Schedule for Energy,

Scenario 1: Market participants who elects to submit a real-time self schedule and/or real-time energy bid curve on top of the real-time self schedule. Under this Scenario, the SCHED value stays as the day-ahead energy schedule MW regardless of the real-time self-schedule MW value. The Supply value is then representing effectively the incremental or decremental offer in real-time.

Scenario 2: No explicit real-time energy bid curve or self schedule is submitted. SIBR will convert the final DA energy schedule into a real-time self schedule

Following examples assume a final day-ahead energy schedule MW as 80MW.

Example 2.1 (incremental),

DOT: 100MW

DOT breakdown is,

SCHED: +80MW

SUPP: +20MW

Example 2.2 (decremental),

DOT: 60MW

DOT breakdown is,

SCHED: +80MW

SUPP: -20MW

7.8.3.1.2 ADS Decline Functionality

In ADS, the CAISO allows Scheduling Coordinators to decline, accept, or partially accept their hourly dispatch schedules or FMM advisory Intertie schedules that clear HASP. The ability to decline or partially-accept an hourly dispatch schedule or FMM advisory Intertie schedule provides Scheduling Coordinators the flexibility to respond to changing system conditions. A Scheduling Coordinator may (1) decline the entire MW value; (2) accept the entire MW value; or (3) partially accept a MW value that does not exceed the HASP schedule. ADS records a final accepted DOT, which is available to the Scheduling Coordinator as "Accept DOT".

For Scheduling Coordinators that have selected the bid options of self-scheduled hourly block, Economic bid hourly block, or Economic bid hourly block with single intra-hour economic schedule change, the accept/decline or partial accept of the MW amount cannot exceed the HASP hourly schedule. For Scheduling Coordinators that have selected the bid options of Economic bid with participation in 15-minute market, the accept/decline or partial accept of the MW amount cannot exceed the largest of the four 15-minute interval advisory schedules from HASP.

The Scheduling Coordinator has up to T-45 to respond to the instructions in ADS following the publication of the HASP results. If the Scheduling Coordinator does not respond, the instruction

will default to accept the schedule generated by the HASP market run. In the event that the Scheduling Coordinator is unable to respond to instructions, the CAISO Operator has the ability to manually change (decline or partially accept) the ADS accepted instruction on the Scheduling Coordinators behalf until T-40.

Decline/Partial Accept Scenario

The HASP cleared schedule = 100 MW

A Scheduling Coordinator can decline the entire amount or partially accept any portion of the 100MW. Therefore, the Accept DOT in ADS will be any number between 0MW to 100MW.

Option 1: Decline of 100 MW. Accept DOT will become 0MW.

Option 2: Partially–accept 60 MW of the HASP schedule. Accept DOT will become 60 MW.

Option 3: Full acceptance of 100MW. Accept DOT will stay as 100MW.

Note: Partial acceptance cannot exceed the cleared HASP schedule (represented as "Hourly DOT" in ADS) even if the cleared HASP schedule is lower than the Scheduling Coordinator's cleared RUC schedule. For example, if a Scheduling Coordinator's has a cleared RUC export schedule of 100 MW and its HASP cleared schedule is 60 MW, the Scheduling Coordinator may partially accept the HASP schedule at a MW value that is less than 60 MW.

7.8.3.1.3 DOT Breakdown in Real-time Dispatch Instruction

The real-time Dispatch Instructions apply to non-hourly pre-dispatch resources, i.e., the Generating Units, tie generators (including Dynamic System Resources and the resources used to model AS import on the ties) and Participating Loads (using the pump-storage model). There are five critical components:

SCHED: The SCHED MW reflects the real-time Energy Self-Schedule for that resource in the SIBR clean bid.

SUPP: The SUPP MW is the difference between DOT and SCHED ~~calculated by (DOT – SCHED).~~ It reflects the incremental (positive) or decremental (negative) value from the Self-Schedule MW. SUPP is inclusive of the SPIN and NSPN MWs and MSSLF whichever applicable.

SPIN: If the resource gets dispatched out of Spinning Operating Reserve capacity (either in contingency or non-contingency mode[53]), this value will reflect dispatched SPIN capacity amount. Otherwise, this amount is zero. SPIN MW can be used for available reserve calculation.

NSPN: If the resource gets dispatched out of Non-Spinning Operating Reserve capacity (either in contingency or non-contingency mode[54]), this value will reflect dispatched Non-Spin capacity amount. Otherwise, this amount is zero. Non-SPIN MW can be used for available reserve calculation.

MSSLF: This only applies to MSS load following resources. If market participants submit MSS load following instructions for the resource, the validated load following instructions will be sent back through this component. For all non-load following resources, this amount will be zero.

Although the standard ramp RMPS is also provided for the real-time Dispatch Instructions in the DOT breakdown, it is recommended the value of RMPS be determined outside of the Dispatch Instruction based on the WECC standard ramp - 20 minute cross-hour ramp between Day-Ahead Schedules over the top of the hour. It is also worth mentioning that, there are two scenarios under which the SCHED will be equal to the final Day-Ahead Schedule for Energy

[53] A contingency AS can only be dispatched in a contingency dispatch run or if the resource is flagged as contingency individually. A non-contingent AS can be dispatched in a normal real-time interval dispatch.

[54] See Note 1.

- **Scenario 1**, for the Market Participants that elects to protect their Day-Ahead Schedule for Energy from changing through the RTM, by itself submitting a Self-Schedule for that same capacity in the Real-Time Market.
- **Scenario 2**: The Market Participant does not submit an explicit Real-Time Energy Bid Curve or Self-Schedule for the MW Energy capacity identified in the Day-Ahead Schedule. SIBR will convert the final Day-Ahead Schedule for Energy into a real-time self-schedule.

Following examples assume a real-time self schedule MW as 80MW,

Example 3.1 (incremental without dispatch out of Spin or Non-Spin),

DOT: 100MW

DOT breakdown is,

SCHED: +80MW

SUPP: +20MW

Example 3.2 (incremental with dispatch out of Spin and Non-Spin),

DOT: 100MW

DOT breakdown is,

SCHED: +80MW

SUPP: +20MW

SPIN: +5MW

NSPN: +5MW

In example 3.2, the 5 MWs dispatched out of Spin and Non-spin are part of the SUPP as the incremental amount. Besides the 5 MWs from Spin and Non-spin, it implies the 20 – 5 -5 = 10MW as the market energy dispatch component.

Example 3.3 (decremental),

DOT: 60MW

DOT breakdown is,

SCHED: +80MW

SUPP: -20MW

Example 3.4 (incremental with dispatch out of Spin, Non-Spin and Load following),

DOT: 100MW

DOT breakdown is,

SCHED: +80MW

SUPP: +20MW

SPIN: +5MW

NSPN: +5MW

MSSLF: +5MW

In example 3.4, the 5 MWs dispatched out of Spin, Non-spin and MSS load following are part of the SUPP as the incremental amount. Besides the 5 MWs from Spin, Non-spin and MSSLF, it implies the 20 – 5 -5 – 5 = 5MW as the market energy dispatch component not associated with any other capacity.

Example 3.5 (decremental with MSS load following),

DOT: 60MW

DOT breakdown is,

SCHED: +80MW

SUPP: -20MW

MSSLF: -5MW

In example 3.5, the -5 MWs for MSS load following are part of the SUPP as the decremental amount. Besides the -5 MWs from MSSLF, it implies the -20 – (-5) = -15MW as the market energy dispatch component.

7.9 Real-Time Contingency Dispatch

This section is based on CAISO Tariff Section 34.3.2, Real-Time Contingency Dispatch.

The Real-Time Contingency Dispatch (RTCD) mode of operation is run in response to a significant Contingency event, such that waiting until the next normal RTED run is not adequate and/or Operating Reserves identified as Contingency Only need to be activated in response to the event. The CAISO Operator may activate Operating Reserves identified as Contingency Only either on a resource-specific basis or for all such resources.

When activating Contingency Only reserves in RTCD, the original Energy Bids associated with the resources providing Operating Reserve are used for the RTCD (CAISO Tariff Section 34.3.2.1). In this case, Dispatch and pricing will be based on original submitted Energy Bids as mitigated by MPM. If no Contingency event has occurred but the CAISO has run out of Economic Bids, the CAISO may dispatch Contingency Only resources in RTED. The RTED will dispatch such resources using Energy Bid cap as provided in Section 39.6.1.1 and will set prices accordingly.

RTCD uses SCED to produce an optimized set of Dispatch Instructions for a single 10-minute Dispatch Interval instead of a normal five-minute Dispatch Interval. It is possible that Dispatch Instructions are issued more than once in the same 5-minute Interval, once from RTED and then later from RTCD. Resources must respond to RTCD Dispatch Instructions as soon as possible. The Dispatch Instructions from RTCD override any previously issued Dispatch Instructions from RTED.

After review by the CAISO Operator, Dispatch Instructions are communicated for the next Dispatch Interval in accordance with Section 6.3 of the CAISO Tariff. When activating an RTCD run and returning to a normal RTED run after an RTCD run, five-minute Dispatch Interval LMPs are produced for each PNode based on the last available price from either the RTCD or normal RTED run relative to a five-minute target Dispatch Interval.

The RTCD application can be activated at any time to address contingencies by dispatching contingent Operating Reserve. Ideally, RTCD should be activated when a State Estimator solution is available after the occurrence of a Contingency that qualifies as a significant event. The SE solution is available normally at the middle of five-minute clock intervals to provide a base operating point for RTED. Nevertheless, SE may also execute and produce a solution immediately after a significant event without waiting for the next regular execution time.

The RTCD is different from the RTED in the following aspects:

- The Dispatch time can be any time.

- When the RTCD is activated, the RTED or RTMD, whichever mode is active, is immediately suspended and may not resume until after the next five-minute Dispatch time.

- Any pending Dispatch Instructions before the RTCD is activated are discarded and not sent to ADS.

- When the RTCD "Include Off-line NSPIN" flag is activated, the system shall apply economic optimization to the unit commitment decisions for off-line resources with Non-Spin awards or qualified self-provisions. RTCD shall only consider off-line resources with Non-Spin awards that are native to the CAISO BAA for unit commitment. Resources that are certified to provide Non-Spin without Non-Spin awards will not be considered. Additionally, economic dispatch for resource capacity included in their entire energy bid (beyond just the Non-Spin awards or qualified self-provisions) will be included in RTCD optimization.

- RTCD solution will not allow MSG resources to transition between configurations. This is enforced to minimize processing time because MSG transition times may exceed the 10-minute RTCD interval.

- For offline resources with Non-Spin awards which get startup instructions in the RTCD run, the commitment instructions will be immediately broadcasted to ADS along with contingency dispatch instructions for other units, and may not align with the existing 15-minute boundary.

- RTCD will not send out a shutdown instruction.

- The time delay between the time the dispatch is initiated and the start of the ramp for the DOT is configurable and initially set to two to three minutes, depending on the complexity of the options chosen by the operator. If the operator chooses a more complex operating mode that typically requires a longer solution time, the three minute value is used, otherwise the two minute value is used. Taking into account the optimization run time and communication delays in ADS, the start of the ramp for the DOT will occur about 90 seconds after receipt of the ADS dispatch instruction. However, because the RTCD is activated in response to a Contingency event, it is expected that resources respond to RTCD instructions as soon as possible.

- Contingent Operating Reserve Bids are automatically released for optimal Dispatch.

- Configurable parameters in RTCD allow the CAISO operator to exclude certain resources from consideration for dispatch:

- Exclude Northern Ties: When the Operator selects this option, the RTCD shall not increment any intertie resources north of Path 26.

- Exclude Southern Ties: When the Operator selects this option, the RTCD shall not increment any intertie resources south of Path 26.

- The Dispatch must be sent to ADS manually by the CAISO Operator; no automatic transfer takes place.

The RTCD calculates a contingent Dispatch for the 10-minute Dispatch Interval, presents the Dispatch to the CAISO Operator, and awaits approval. The CAISO Operator may block or edit individual Dispatches as usual, and then manually sends the Dispatch to ADS, or blocks and discards the entire Dispatch. The RTCD stays idle afterwards awaiting CAISO Operator action, however, the RTUC continues running every 15 minutes.

The CAISO Operator may manually initiate another RTCD run, or switch to RTED or RTMD, which resumes at the next applicable dispatch time (the midpoint of a five-minute clock interval). The RTED or RTMD inherits the global Contingency status from the RTCD and does not automatically unload contingent Operating Reserve. That action is performed by the CAISO Operator manually resetting the resource-specific Contingency Flags gradually during the remainder of the hour (in reverse merit order of their Energy Bid). This gradual reserve pickup is necessary to avoid large Generation swings immediately after surviving a Contingency.

A special mode of RTCD, called Real-Time Disturbance Dispatch or RTDD (CAISO Tariff Section 34.3.2.2), can be invoked by the CAISO Operator when 300 MW or more of capacity is needed to respond to a significant Contingency event. RTDD will not use SCED. RTDD is a merit order dispatch without a network model.

- Under RTDD, priority will be given to resources with available Operating Reserve capacity, then to resources with ramping capability as follows. Tier 1 resources will be selected before Tier 2.

    - Tier 1: Resources with Spinning Reserves and Non-Spinning Reserves will be chosen in merit order of price for Operating Reserves, not Energy Bid price. For example, if the CAISO needs 100 MW and there are two units (A and B) providing Operating Reserves, with unit A being awarded 10 MW at $10/MW, unit B being awarded 100 MW at $15/MW, the order will be 10 MW from unit A and 90 MW from unit B.

    - Tier 2: Resources with Energy-only bids or resources with remaining available ramping capability will be chosen in descending order of effective available MW

within the 10-minute ramping capability of the unit (i.e., the remaining amount after considering the available Operating Reserves from Tier 1 above). For example, If after exhausting all the available capacity in Tier 1, the CAISO needs 50 more MW and there are two units (A and B) with Energy-only bids and available ramping capability, unit A with 10 MW of ramping capability at $10/MW and unit B with 100 MW of ramping capability at $15/MW, the system will use 50 MW from unit B even though it is more expensive.

- At the CAISO Operator's discretion, priority may be given to resources located in a particular dispatch region within the CAISO balancing authority. For example, if a major resource trips in the San Diego area, the CAISO Operator may want to give dispatch priority to the remaining resources in the San Diego area to ensure recovery from the disturbance. A parameter in RTDD will allow the operator to determine whether to give priority to dispatch regions and, if so, which dispatch region to give priority to.

- Resources must respond to RTDD Dispatch Instructions as soon as possible.

- RTDD will not enforce transmission constraints. In addition the dispatch will be a uni-directional dispatch, since the expectation is that resources would be dispatched upward to make up for the lost energy due to the contingency.

7.9.1 Real-Time Contingency Dispatch Inputs

This section lists the inputs that are particularly specific to RTCD. Inputs that are common to all the DAM functions are identified in earlier sections of this BPM:

- The Load prediction for the RTCD Dispatch Interval is the projected average of the system Load over the 10-minute RTCD Dispatch Interval. It is derived as a time-weighted average of the Load prediction for the overlapping five-minute clock Dispatch Intervals.

- The Load prediction may be adjusted by CAISO Operator to reflect actual conditions that could not be incorporated into the prediction.

7.9.2 Real-Time Contingency Dispatch Constraints & Objectives

RTCD uses SCED to produce an optimized set of Dispatch Instructions for a single 10-minute Dispatch Interval instead of a normal five-minute Dispatch Interval. After being reviewed by the CAISO Operator, Dispatch Instructions are communicated for the next Dispatch Interval in accordance with Section 6.3 of the CAISO Tariff.

7.9.3 Real-Time Contingency Dispatch Locational Marginal Prices and Load Forecast

Metering and Settlement are aligned with five-minute clock Dispatch Interval, hence LMPs must be determined for the same intervals. This is not a problem for the RTED or RTMD since they both align with five-minute clock Dispatch Intervals, and if a RTMD run is skipped, the MCP remains the same as that of the previous Dispatch Interval. However, the RTCD Dispatch Intervals, and thus the RTCD LMPs, do not align with five-minute clock Dispatch Intervals. In this case, the rules for determining the five-minute clock Dispatch Interval LMPs are as follows:

- The RTCD LMPs determine the five-minute clock Dispatch Interval LMPs for all five-minute clock Dispatch Intervals that overlap with the RTCD Dispatch Interval.
- The final five-minute clock Dispatch Interval LMP, which is used for Settlement, is the last determined LMP for that Dispatch Interval, if there are multiple instances due to Dispatch overlap or multiple Dispatch runs.
- If LMPs for a five-minute clock Dispatch Interval are somehow undetermined, e.g., because a Dispatch was skipped or missed, the LMPs for the previous five-minute clock Dispatch Interval apply.

In general, the RTCD Dispatch Interval overlaps with three five-minute clock Dispatch Intervals. Assuming normal transition from RTED to RTCD and then back to RTED, the LMPs for the three overlapping five-minute clock Dispatch Intervals are determined according to the rules as follows:

- The LMPs for the first five-minute clock Dispatch Interval that overlaps with the RTCD Dispatch Interval are first calculated by the last RTED run, but then are overwritten with the RTCD LMPs.
- The LMPs for the second five-minute clock Dispatch Interval that overlaps with the RTCD Dispatch Interval are the RTCD LMPs. No binding LMPs are available from RTED for this interval.
- The LMPs for the third five-minute clock Dispatch Interval that overlaps with the RTCD Dispatch Interval are first calculated by RTCD, but then are overwritten by the next RTED LMPs.

LMPs in the RTCD are calculated in the same manner as in the RTED, except that LMPs in the RTDD are determined on a system-wide basis. Under RTDD dispatches, the system marginal Energy component is set to the Energy Bid of the highest-priced resource dispatched,

regardless of in which tier or dispatch region the resource was dispatched. The marginal loss and congestion components are zero in the RTDD.

Similar to LMPs, Settlement uses a five-minute clock Dispatch Interval load forecast. The forecast is used to weigh the five-minute clock Dispatch Interval LMP for production of an hourly weighted average price for non-participating load imbalance deviations. In order to provide the correct weighting, the five minute clock Dispatch Interval load forecast under a RTCD run is determined in the same manner as described for the LMPs above, using the RTCD 10-minute load forecast, including any operator adjustments.

7.9.4 Real-Time Contingency Dispatch Outputs

When activating a RTCD and returning to normal RTED run after a RTCD run, five-minute Dispatch Interval LMPs are produced for each PNode based on the last available price from either the RTCD or normal RTED run relative to a five-minute target Dispatch Interval.

7.9.4.1 Real-Time Dispatch Logic for Non-Dynamic System Resources

In general, the Real-Time Dispatch will match energy awards from HASP or FMM, including any adjustments by CAS. However, if the CAISO awards a Non-Dynamic System Resource Ancillary Services in the IFM or HASP and issues a Dispatch Instruction in the middle of the Trading Hour for Energy associated with its Ancillary Services (Operating Reserve) capacity, the CAISO will Dispatch the Non-Dynamic System Resource to operate at a constant level until the end of the Trading Hour. This means that Dispatch outputs from subsequent RTED or RTCD for the rest of the Trading Hour will be set at the constant level unless adjusted by a later CAS confirmed Dispatch. If the CAISO dispatches a Non-Dynamic System Resource such that the Dispatch (DOT) at the end of the 10-min ramp is in the next Trading Hour, the CAISO will dispatch Energy from the Non-Dynamic System Resource at a constant level until the end of the next Trading Hour using the Energy Bid and Operating Reserve award for that hour. The dispatched Energy will not exceed the awarded Operating Reserve capacity in the next Trading Hour. The energy associated with ancillary services from a Non-Dynamic System Resource can only be dispatched once during an hour.

7.10 Real-Time Manual Dispatch

This section is based on CAISO Tariff Section 34.3.3, Real-Time Manual Dispatch.

The Real-Time Manual Dispatch (RTMD) mode of operation is a merit-order run activated upon CAISO Operator action as a backup process in case the normal RTED process fails and expected to continue to fail to converge and solve. This may be due to invalid or unreasonable resource constraints, problems with the AC powerflow solutions, unreasonable transmission constraints, issues with State Estimator solution, or other adverse system conditions. The CAISO Operator may relax certain constraints or choose to solve a Powerflow as part of the RTED before they revert to a RTMD. The RTMD run provides the CAISO Operator a list of resources and quantity of MW available for Dispatch in merit-order based on Operational Ramp Rate but otherwise ignores Transmission Losses and network constraints.

The CAISO Operator may Dispatch resources from the list by identifying the quantity of Imbalance Energy that is required for the system and/or directly selecting resources from the merit order taking into consideration actual operating conditions. After Dispatches have been selected, reviewed and accepted by the CAISO Operator, Dispatch Instructions are communicated in accordance with Section 6.3 of the CAISO Tariff.

While the RTMD mode is being used for Dispatch, a uniform five-minute Market Clearing Price (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.

The Real-Time Manual Dispatch application is a backup Dispatch process that can be activated at any time when the RTED fails to converge because of bad data, network model issues, or optimization engine failure. When activated, the RTMD executes every five minutes in place of the RTED at the same dispatch times, until the CAISO Operator switches back to the RTED. However, the other applications, namely RTUC, HASP, and STUC, continue to execute normally every 15 minutes and every hour.

The RTMD is different from the RTED in the following aspects:

- RTMD has a single five-minute Dispatch Interval.
- Resources are Dispatched in merit order based on Energy Bids and Ramp Rate limits, but ignoring Transmission Losses and network constraints. The CAISO Operator is presented a merit order list of feasible Bids (in terms of ramp capability) and a system Imbalance Energy requirement that needs to be met. Bids are selected, and Dispatched in the merit order list to meet the Imbalance Energy requirement.

- The Dispatch must be sent to ADS manually by the CAISO Operator; no automatic transfer takes place.

- A system-wide Market Clearing Price (as opposed to LMPs) is produced for the Dispatch Interval. Area or zonal restrictions are dealt with on a manual basis by the CAISO Operator.

Aside from these differences, the Dispatch times are still aligned with the DOTs at the middle of five-minute clock intervals and the resource output is still projected from the actual output at that point in time toward the last DOT.

The RTMD, similarly to the RTED, does not dispatch contingent Operating Reserves under normal system conditions. The RTMD may dispatch contingent Operating Reserves, though when the CAISO Operator activates the Contingency status.

7.10.1 Real-Time Manual Dispatch Inputs

Other than CAISO Operator initiation, this section lists the inputs that are particularly specific to RTMD. Inputs that are common to all the RTM functions are identified in earlier sections of this BPM:

- By supplying an Imbalance Energy requirement, RTMD generates a merit order list of instructions.

- The CAISO Operator has the ability to manually add, remove, or modify instructions from the merit order list. Resources that are "removed" from the merit order list are not dispatched.

- The CAISO Operator has the ability to Dispatch contingent Ancillary Services.

7.10.2 Real-Time Manual Dispatch Constraints & Objectives

Since no SCUC optimization takes place in the RTMD, the execution time is very short. Therefore, the CAISO Operator has a time delay window of about five minutes after the merit order list is presented until the start of the ramp at the middle of the next five-minute clock interval, to review, modify, and commit the Dispatch. If the Dispatch is not sent by that time, it is discarded and a new merit order list is presented for the following Dispatch Interval based on the updated data (actual output and Load prediction) that become available at that time. The DOT and MCP for the Dispatch Interval that the Dispatch is discarded remain equal to the DOT and MCP of the previous Dispatch Interval.

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.

If the market clearing process cannot reach a feasible solution while enforcing resource constraints, the market will experience a disruption for that market run. For the day-ahead market, the CAISO will identify and take steps to address the cause of the market failure. This may include manual actions that result in delays in completing the market run and publishing market results. For the real-time market, the market clearing process has logic to use a solution from a previous market run for a limited number of intervals while the CAISO identifies and addresses the issue. To address or prevent the market disruption, the CAISO market run can exclude certain resources that create the infeasibility. Market operators may take manual steps to make these resources non-participating. When this occurs, scheduling coordinators for the impacted resources receive notification, and the CAISO provides a list of instances in public reports of market disruptions. The CAISO will also use automated logic in the relevant clearing process that allows the market to identify resource constraints that will lead to a market disruption:

- RTD: The logic in RTD will identify the resource-level constraints that contribute to the infeasibility and replace the individual resource dispatch with the last feasible dispatch, thereby achieve a market solution. This logic effectively prevents the market disruption and eliminates the need to exclude resources from participating in the market.

- RTPD: No automation to identify and replace an RTPD commitment at this time.
- STUC: The logic in STUC will relax the constraint only for the individual resource dispatch that contributed to the infeasibility therefore achieving a market solution. As STUC produces non-binding commitments this logic also effectively prevents market disruptions and eliminates the need to exclude resources from participating in the market.

Resource Constraint Examples:

- Ramping Constraint. MSG Resource has a Base Schedule in a CT configuration at 110MW. Ramp rate of 1.5MW/min is not able to reach its next hour 1x1 MSG Configuration Base Schedule of 220MW.
- NGR State of Charge. The combination of telemetered SOC and bid limits may not allow a valid dispatch. For example, if the initial SOC is 4 MW, the bid SOC max is 3 MW, and there are no discharge bids submitted there may be no feasible way to dispatch the resource.

For transparency, the CAISO will report on the events where this logic triggers using monthly market performance reports. The information will include the list of markets when this logic was used, including the type of constraint relaxed.

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) 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.

7.10.4.3 Reporting to affected Scheduling Coordinators

In the event that a Bid is removed, the Scheduling Coordinator's Bid will not be cleared through the specific CAISO Market from which it was removed. The CAISO will notify the Scheduling Coordinator as soon as practicable, but no later than three (3) Business Days, after the applicable Bid was removed and will provide information specifying when its Bid was removed and the nature of the disruption.

7.11 Exceptional Dispatch

This section is based on CAISO Tariff Section 34.11, Exceptional Dispatch.

CAISO may perform Exceptional Dispatches for the circumstances described in section 34.11 of the CAISO Tariff, which may require the issuance of forced Shut-Downs or forced Start-Ups, or forced MSG Transitions. CAISO conducts all Exceptional Dispatches consistent with Good Utility Practice.

Dispatch Instructions issued pursuant to Exceptional Dispatches are entered manually by the CAISO Operator into the RTM optimization software so that they are accounted for and included in the communication of Dispatch Instructions to SCs. CAISO Operators may also communicate an Exceptional Dispatch instruction directly to the Scheduling Coordinator. In addition, CAISO Operators may also manually dispatch Non-Dynamic System Resources but only to the extent Bids from those resources are available, in which case instructions are entered in CAS. The goal of CAISO Operators will be to issue Exceptional Dispatches on a least cost basis.

See CAISO Operating Procedure M-402, Exceptional Dispatch for more information.

Exceptional Dispatches are not derived through the use of the RTM optimization software and are not used to establish the LMPs at the applicable PNodes. CAISO records the circumstances

that have led to the Exceptional Dispatch. Imbalance Energy delivered or consumed pursuant to the various types of Exceptional Dispatch are settled according to the provisions in Section 11, subject to Section 39.10 when Bid mitigation may apply, of the CAISO Tariff.

Resources receiving Exceptional Dispatches may be eligible for supplemental revenues pursuant to CAISO Tariff Section 39 or Interim Capacity Payment Mechanism capacity payments pursuant to CAISO Tariff Section 43. Additional details on eligibility are set forth in the Business Practice Manuals for Reliability Requirements.

7.11.1 System Reliability Exceptional Dispatches

This section is based on CAISO Tariff Section 34.11.1, System Reliability Exceptional Dispatches.

CAISO manually dispatches Generating Units (including Multi-Stage Generating Resources), Participating Loads, Dynamic System Resources, RDRR resources, and Condition 2 LRMR Units, in addition to or instead of resources dispatched by RTM optimization software during a System Emergency, or to prevent an imminent System Emergency or a situation that threatens System Reliability and cannot be addressed by the RTM optimization and system modeling.

A System Emergency is defined by the CAISO Tariff as including any "Condition beyond the normal control of the CAISO that affect the ability of the CAISO Balancing Authority Area to function normally, including any abnormal system condition which requires immediate manual or automatic action to prevent loss of Load, equipment, tripping of system elements which might result in cascading Outages or to restore operation to meet Applicable Reliability Criteria."

CAISO Operators will utilize its System Emergency Exceptional Dispatch authority unless the more specific authorities under Sections 34.11.2 or 34.11.3, discussed below, are clearly applicable. These would include Exceptional Dispatches for any reason CAISO Operators need to address a System Emergency which cannot be addressed by the RTM optimization or system modeling including: Generation and transmission outages; resource specific constraints, such as Forbidden Operating Regions; market software constraints; transmission related modeling limitations, such as South of P26 – Inability to model the loss of the DC, unless Section 34.11.3 applies, as discussed below.

To the extent possible, CAISO utilizes available and effective Bids from resources before dispatching resources without Bids. To deal with any threats to System Reliability, CAISO also dispatches in the Real-Time, Non-Dynamic System Resources that are not selected by the RTM for Dispatch, but for which the relevant SC has submitted a Bid into RTM.

7.11.2 Other Exceptional Dispatch

This section is based on CAISO Tariff Section 34.11.2, Other Exceptional Dispatch.

CAISO may also issue Exceptional Dispatches to resources in addition to or instead of resources dispatched by the RTM optimization software for the following specific reasons:

1) Perform A/S testing
2) Perform pre-commercial operations testing
3) Perform PMax testing
4) Mitigate for over-generation
5) Provide for Black Start
6) Provide for Voltage Support
7) Accommodate TOR or ETC self-schedule changes after the Market close of the RTM
8) Reverse a commitment instruction issued through the IFM that is no longer optimal as determined through RUC,
9) In the event of a Market Disruption, to prevent a Market Disruption or to minimize the extent of a Market Disruption; or
10) To reverse the operating mode of a Pumped-Storage Hydro Unit.

7.11.3 Transmission-Related Modeling Limitations

This section is based on CAISO Tariff Section 34.11.3, Transmission-Related Modeling Limitations.

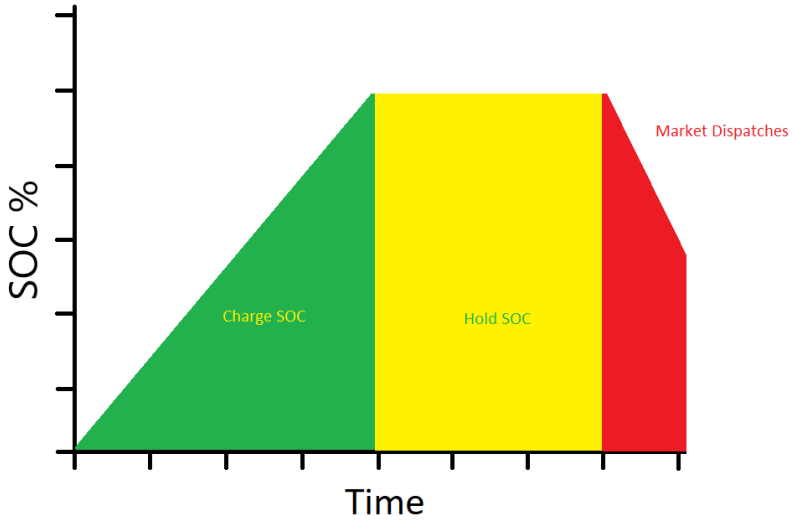
CAISO Operators may also issue Exceptional Dispatches to address transmission-related modeling limitations in the Full Network Model that arise from transmission maintenance, lack of Voltage Support at proper levels as well as incomplete or incorrect information about the transmission network, for which the Participating Transmission Owners have primary responsibility. The cost allocation, as described in Section 11.5.6.2.5 is different from the cost allocation of System Emergency Exceptional issues pursuant to Section 34.9.1 as Excess Cost Payments will be allocated to the responsible Participating Transmission Owner.

CAISO Operators can also issue Exceptional Dispatches under CAISO Tariff Section 34.11.3 in response to system conditions including threatened or imminent reliability conditions for which

the timing of the Real-Time Market optimization and system modeling are either too slow or incapable of bringing the CAISO Controlled Grid back to reliable operations in an appropriate time-frame based on the timing and physical characteristics of available resources to the CAISO. The settlement price and cost allocation for these Exceptional Dispatches are the same as for Exceptional Dispatches issues pursuant to Section 34.11.1.

7.11.4 Holding and Charging State-of-Charge (SOC)

To help ensure system reliability, individual storage resources may be exceptionally dispatched to charge and then hold the charge to be used at later time specifically the peak or net-peak load time-period of the day. A "charge" State of Charge (SOC) Exceptional Dispatch shall be where Instruction Type equals "Fixed" and where GoTo MWs at the given resource's full, or close to full, negative Pmin. This will allow the resource to charge from the grid as quickly and efficiently as possible. To "hold" the SOC, the Exceptional Dispatch shall be where Instruction type equals "Fixed" and at the GoTo MWs at 0 (zero). As a result, battery resources shall ideally be available for market dispatches at the most critical time period of the day, as depicted below:



Storage resources will be compensated for hold SOC EDs using a different methodology than traditional exceptional dispatch. The compensation will be based on an opportunity cost methodology and will capture the revenues that the resource would have received had it been optimally participating in the market, both during the exceptional dispatch and for a period of time after the exceptional dispatch. The calculation is based upon two counterfactual values including the maximum revenue energy dispatch the resource would have received if there was no exceptional dispatch in place, and the maximum revenue energy dispatch that the resource would have received if the exceptional dispatch was still in place. The time horizon for these counterfactuals will start from the first interval where the exceptional dispatch to hold state of charge is in place. If the resource would have been able to make additional revenue if the exceptional dispatch was not in place, then the resource would be awarded the difference between the counterfactual revenue earned without the exceptional dispatch in place and with the exceptional dispatch in place, as an additional uplift payment for the day. Counterfactuals in the real-time market will be based on imbalances from day-ahead schedules, similar to typical real-time settlement practices. Note that if the resource would not have been able to make additional revenue if the exceptional dispatch was not in place, no additional uplift payment (positive or negative) will be compensated for the day.

Example:

ESE SOC Hold ED Example A: High RTD Prices During HOLD ED

IN THIS EXAMPLE:
-Storage Resource is issued Charge ED, then Hold SOC ED.
-RTD prices are high during the Hold SOC ED, triggering in payment.
-Storage Resource SOC maximum = 300 MW.

This bid curve applies to all hours below:

RTD Final Bid	
MWh	$/MWh
-75	$ (100)
-15	$ 5
0	$ 10
40	$ 85
50	$ 120
75	$ 120

Hour	RTD Int	RTD LMP ($/MWh)	Hold/ Charge ED (MWh)	Counterfactual With Hold SOC ED					Counterfactual Without Hold SOC ED					W/o Hold less with Hold ($)
				Economic Dispatch (MWh)	ED Impact (MWh)	SOC (MWh)	Dispatch (MWh)	Revenue ($)	Economic Dispatch (MWh)	ED Impact (MWh)	SOC (MWh)	Dispatch (MWh)	Revenue ($)	
HE 12	1	$ 45	Fix -75	n/a	-75	200	n/a		n/a	-75	200	n/a		
	2	$ 55	Fix -75	n/a	-75	213	n/a		n/a	-75	213	n/a		
	3	$ 65	Fix -75	n/a	-75	225	n/a		n/a	-75	225	n/a		
	4	$ 75	Fix -75	n/a	-75	238	n/a		n/a	-75	238	n/a		
	5	$ 85	Fix -75	n/a	-75	250	n/a		n/a	-75	250	n/a		
	6	$ 83	Fix -75	n/a	-75	263	n/a		n/a	-75	263	n/a		
	7	$ 81	Fix -75	n/a	-75	275	n/a		n/a	-75	275	n/a		
	8	$ 85	Fix -75	n/a	-75	288	n/a		n/a	-75	288	n/a		
	9	$ 72	Fix -75	n/a	-75	300	n/a		n/a	-75	300	n/a		
	10	$ 70	Hold	40	0	300	0	0	40		300	40	233	
	11	$ 75	Hold	40	0	300	0	0	40		297	40	250	
	12	$ 68	Hold	40	0	300	0	0	40		293	40	227	
HE 12 Subtotals			Charge/Hold	40	0	300	0	$ -	40		293	40	$ 710	$ 710
HE 13	1	$ 75	Hold	40	0	300	0	0	40		290	40	250	
	2	$ 78	Hold	40	0	300	0	0	40		287	40	260	
	3	$ 85	Hold	50	0	300	0	0	50		283	50	354	
	4	$ 130	Hold	75	0	300	0	0	75		279	75	813	
	5	$ 215	Hold	75	0	300	0	0	75		273	75	1344	
	6	$ 250	Hold	75	0	300	0	0	75		267	75	1563	
	7	$ 295	Hold	75	0	300	0	0	75		260	75	1844	
	8	$ 320	Hold	75	0	300	0	0	75		254	75	2000	
	9	$ 400	Hold	75	0	300	0	0	75		248	75	2500	
	10	$ 440	Hold	75	0	300	0	0	75		242	75	2750	
	11	$ 410	Hold	75	0	300	0	0	75		235	75	2563	
	12	$ 200	Hold	75	0	300	0	0	75		229	75	1250	
HE 13 Subtotals			Hold	75	0	300	0	$ -	75		229	75	$ 17,489	$ 17,489

Hour	RTD Int	RTD LMP ($/MWh)	Hold/ Charge ED (MWh)	Counterfactual With Hold SOC ED					Counterfactual Without Hold SOC ED					W/o Hold less with Hold ($)
				Economic Dispatch (MWh)	ED Impact (MWh)	SOC (MWh)	Dispatch (MWh)	Revenue ($)	Economic Dispatch (MWh)	ED Impact (MWh)	SOC (MWh)	Dispatch (MWh)	Revenue ($)	
HE 14	1	$ 150	Hold	75	0	300	0	0	75		223	75	938	
	2	$ 123	Hold	75	0	300	0	0	75		217	75	769	
	3	$ 98	Hold	50	0	300	0	0	50		210	50	408	
	4	$ 75	Hold	40	0	300	0	0	40		206	40	250	
	5	$ 89	Hold	50	0	300	0	0	50		203	50	371	
	6	$ 95	Hold	50	0	300	0	0	50		199	50	396	
	7	$ 100	Hold	50	0	300	0	0	50		195	50	417	
	8	$ 110	Hold	50	0	300	0	0	50		190	50	458	
	9	$ 100	Hold	50	0	300	0	0	50		186	50	417	
	10	$ 91	Hold	50	0	300	0	0	50		182	50	379	
	11	$ 72	Hold	40	0	300	0	0	40		178	40	240	
	12	$ 64	Hold	40	0	300	0	0	40		175	40	213	
HE 14 Subtotals			Hold	40	0	300	0	$ -	40		171	40	$ 5,255	$ 5,255
HE 15	1	$ 78	No	40		300	40	260	40		168	40	260	
	2	$ 96	No	50		297	50	400	50		165	50	400	
	3	$ 125	No	75		293	75	781	75		160	75	781	
	4	$ 128	No	75		286	75	800	75		154	75	800	
	5	$ 121	No	75		280	75	756	75		148	75	756	
	6	$ 135	No	75		274	75	844	75		142	75	844	
	7	$ 150	No	75		268	75	938	75		135	75	938	
	8	$ 130	No	75		261	75	813	75		129	75	813	
	9	$ 138	No	75		255	75	863	75		123	75	863	
	10	$ 142	No	75		249	75	888	75		117	75	888	
	11	$ 110	No	50		243	50	458	50		110	50	458	
	12	$ 100	No	50		238	50	417	50		106	50	417	
HE 15 Subtotals			No	50		238	50	$ 8,216	50		106	50	$ 8,216	$ -

Hour	RTD Int	RTD LMP ($/MWh)	Hold/ Charge ED (MWh)	Counterfactual With Hold SOC ED					Counterfactual Without Hold SOC ED					W/o Hold less with Hold ($)
				Economic Dispatch (MWh)	ED Impact (MWh)	SOC (MWh)	Dispatch (MWh)	Revenue ($)	Economic Dispatch (MWh)	ED Impact (MWh)	SOC (MWh)	Dispatch (MWh)	Revenue ($)	
HE 16	1	$ 110	No	50		234	50	458	50		102	50	458	
	2	$ 115	No	50		230	50	479	50		98	50	479	
	3	$ 120	No	75		226	75	750	75		94	75	750	
	4	$ 130	No	75		220	75	813	75		88	75	813	
	5	$ 132	No	75		213	75	825	75		81	75	825	
	6	$ 145	No	75		207	75	906	75		75	75	906	
	7	$ 150	No	75		201	75	938	75		69	75	938	
	8	$ 142	No	75		195	75	888	75		63	75	888	
	9	$ 141	No	75		188	75	881	75		56	75	881	
	10	$ 135	No	75		182	75	844	75		50	75	844	
	11	$ 148	No	75		176	75	925	75		44	75	925	
	12	$ 137	No	75		170	75	856	75		38	75	856	
HE 16 Subtotals			No	75		170	75	$ 9,563	75		38	75	$ 9,563	$ -
HE 17	1	$ 62	No	40		163	40	207	40		31	40	207	-
	2	$ 45	No	40		160	40	150	40		28	40	150	-
	3	$ 31	No	40		157	40	103	40		25	40	103	-
	4	$ 10	No	40		153	40	33	40		21	40	33	-
	5	$ 7	No	-15		150	-15	-9	-15		18	-15	-9	-
	6	$ (2)	No	-75		151	-75	13	-75		19	-75	13	-
	7	$ (4)	No	-75		158	-75	25	-75		25	-75	25	-
	8	$ (20)	No	-75		164	-75	125	-75		32	-75	125	-
	9	$ (25)	No	-75		170	-75	156	-75		38	-75	156	-
	10	$ (15)	No	-75		176	-75	94	-75		44	-75	94	-
	11	$ 35	No	40		183	40	117	40		50	40	117	-
	12	$ 45	No	40		179	40	150	40		47	40	150	-
HE 17 Subtotals			No	40		179	40	$ 1,164	40		47	40	$ 1,164	$ -

Hour	RTD Int	RTD LMP ($/MWh)	Hold/ Charge ED (MWh)	Counterfactual With Hold SOC ED					Counterfactual Without Hold SOC ED					W/o Hold less with Hold ($)
				Economic Dispatch (MWh)	ED Impact (MWh)	SOC (MWh)	Dispatch (MWh)	Revenue ($)	Economic Dispatch (MWh)	ED Impact (MWh)	SOC (MWh)	Dispatch (MWh)	Revenue ($)	
HE 17 Subtotals			No	40		179	40	$ 1,164	40		47	40	$ 1,164	$ -
HE 18	1	$ 65	No	40		176	40	217	40		44	40	217	
	2	$ 78	No	40		173	40	260	40		40	40	260	
	3	$ 75	No	40		169	40	250	40		37	40	250	
	4	$ 60	No	40		166	40	200	40		34	40	200	
	5	$ 45	No	40		163	40	150	40		30	40	150	
	6	$ 32	No	40		159	40	107	40		27	40	107	
	7	$ 46	No	40		156	40	153	40		24	40	153	
	8	$ 78	No	40		153	40	260	40		20	40	260	
	9	$ 90	No	50		149	50	375	50		17	50	375	
	10	$ 128	No	75		145	75	800	75		13	75	800	
	11	$ 135	No	75		139	75	844	75		7	75	844	
	12	$ 127	No	75		133	75	794	75		0	75	794	
HE 18 Subtotals			No	75		133	75	$ 4,409	75		0	75	$ 4,409	$ -
HE 19	1	$ 125	No	75		126	75	781	75		0	0	0	
	2	$ 115	No	50		120	50	479	50		0	0	0	
	3	$ 117	No	50		116	50	488	50		0	0	0	
	4	$ 112	No	50		112	50	467	50		0	0	0	
	5	$ 114	No	50		108	50	475	50		0	0	0	
	6	$ 110	No	50		103	50	458	50		0	0	0	
	7	$ 108	No	50		99	50	450	50		0	0	0	
	8	$ 105	No	50		95	50	438	50		0	0	0	
	9	$ 98	No	50		91	50	408	50		0	0	0	
	10	$ 94	No	50		87	50	392	50		0	0	0	
	11	$ 96	No	50		82	50	400	50		0	0	0	
	12	$ 94	No	50		78	50	392	50		0	0	0	
HE 19 Subtotals			No	50		78	50	$ 5,627	50		0	0	$ -	$ (5,627)

Hour	RTD Int	RTD LMP ($/MWh)	Hold/ Charge ED (MWh)	Counterfactual With Hold SOC ED					Counterfactual Without Hold SOC ED					W/o Hold less with Hold ($)
				Economic Dispatch (MWh)	ED Impact (MWh)	SOC (MWh)	Dispatch (MWh)	Revenue ($)	Economic Dispatch (MWh)	ED Impact (MWh)	SOC (MWh)	Dispatch (MWh)	Revenue ($)	
HE 19 Subtotals			No	50		78	50	$ 5,627	50		0	0	$ -	$ (5,627)
HE 20	1	$ 120	No	75		74	75	750	75		0	0	0	
	2	$ 123	No	75		68	75	769	75		0	0	0	
	3	$ 128	No	75		62	75	800	75		0	0	0	
	4	$ 130	No	75		55	75	813	75		0	0	0	
	5	$ 114	No	75		49	75	713	75		0	0	0	
	6	$ 110	No	75		43	75	688	75		0	0	0	
	7	$ 108	No	75		37	75	675	75		0	0	0	
	8	$ 105	No	75		30	75	656	75		0	0	0	
	9	$ 98	No	75		24	75	613	75		0	0	0	
	10	$ 94	No	75		18	75	588	75		0	0	0	
	11	$ 96	No	75		12	75	600	75		0	0	0	
	12	$ 94	No	75		5	75	588	75		0	0	0	
HE 20 Subtotals			No	75		5	75	$ 8,250	75		0	0	$ -	$ (8,250)
HE 21	1	$ 90	No	50		0	50	375	50		0	0	0	
	2	$ 85	No	50		0	0	0	50		0	0	0	
	3	$ 80	No	40		0	0	0	40		0	0	0	
	4	$ 75	No	10		0	0	0	10		0	0	0	
	5	$ 55	No	40		0	0	0	40		0	0	0	
	6	$ 42	No	40		0	0	0	40		0	0	0	
	7	$ 37	No	40		0	0	0	40		0	0	0	
	8	$ 38	No	40		0	0	0	40		0	0	0	
	9	$ 29	No	40		0	0	0	40		0	0	0	
	10	$ 45	No	40		0	0	0	40		0	0	0	
	11	$ 38	No	40		0	0	0	40		0	0	0	
	12	$ 35	No	40		0	0	0	40		0	0	0	
HE 21 Subtotals			No	0		0	0	$ 188	0		0	0	$ -	$ (188)
HE 22 Subtotals			No	0		0	0	$ -	0		0	0	$ -	$ -
HE 23 Subtotals			No	0		0	0	$ -	0		0	0	$ -	$ -
HE 24 Subtotals			No	0		0	0	$ -	0		0	0	$ -	$ -
							Total Revenue	$ 37,510				Total Revenue	$ 46,806	
													Final Uplift:	*$ 9,390*

8. Tagging

8.1 What is an E-Tag?

Pursuant to Appendix A to the ISO tariff, an E-Tag is an electronic tag associated with an Interchange Schedule in accordance with the requirements of WECC.[55] WECC, in turn, defines Electronic Tag or E-Tag as a document describing a physical interchange transaction and its associated participants. In plain terms, an E-Tag is the tool used to track energy delivery from one balancing authority to another balancing authority (*i.e.*, imports and exports) or from the source to the sink Balancing Authority Area (BAA).

[55] The ISO capitalizes the "E" "E-Tag" even though most entities do not (*i.e.*, e-Tag) to make it clear for the reader that it is a defined term under Appendix A to the ISO tariff.

8.2 Who Is Required to E-Tags?

Scheduling Coordinators and Purchasing Selling Entities (or other entities with similar NERC and North American Energy Standards Board (NAESB) registration) are required to tag interchange schedules between balancing Authority Areas. Interchange Schedules are Energy Schedules where electric power is transferred between Balancing Authority Areas, and they require coordination among multiple entities. The primary method for providing this coordination is the E-Tag. As detailed below, various entities can communicate important information pertaining to the Interchange transaction to each other via the internet using computer applications, which are based on the E-Tag specifications maintained by the NAESB.

A Scheduling Coordinator can communicate interchange transaction information to reliability entities using E-Tags, including Balancing Authorities such as the ISO. Similarly, a reliability entity can communicate reliability limits on interchange transactions to PSEs and other reliability entities using E-Tags. E-Tags should be prepared by PSEs in accordance with NERC, NAESB, WECC, and ISO requirements to facilitate effective operations between Balancing Authority Areas within the Western Interconnection.

8.2.1 Imports/Exports

E-Tags are required for all interchange transaction schedules, that is, all imports or exports on the interties. Transactions that are entirely within the ISO BAA using ISO transmission such as Scheduling Coordinator to Scheduling Coordinator trades are considered network transmission service and are not tagged.

8.2.1.1 Pseudo-Ties

Virtual interconnections aside, pseudo-tie energy inherently crosses BAAs. Accordingly, Pseudo intertie Energy transactions must be e-Tagged. Pseudo Tie E-Tags will follow the same criteria as Dynamic Tag Types 4. Pursuant to Section 1.2.1.2 of the ISO's pseudo-tie protocol (Appendix N to the ISO tariff), a pseudo-tie generating unit must transfer dynamically its entire output at one associated pre-determined ISO Intertie, and the unit "must be permanently associated with a particular pre-determine ISO Intertie." While the same section gives the ISO the discretion to allow for a change in the pre-established Intertie—subject to approval by affected transmission owners—the ISO currently does not have the technical ability to allow the use of two pre-established locations (*e.g.*, one associated pre-determined Intertie and another associated pre-determined Intertie simultaneously). Pseudo-tie generating units may, however, propose changes to their associated Intertie with advance notice and following Operating Procedure 2510 NERC Tagging Requirements.

8.2.1.2 Dynamic Resources

A "dynamic transfer" is the transfer of energy or ancillary services from resources in one BAA into another BAA.[56] The two basic categories of dynamic transfers are Dynamic Schedules and Pseudo-Ties. A dynamic transfer is a "Dynamic Schedule" when the resource supplying the energy or ancillary services remains under the control of the BAA where the resource is interconnected. The ISO tariff defines Dynamic Schedule as "A telemetered reading or value which is updated in Real-Time and which is used as an Interchange Schedule in the CAISO Energy Management System calculation of Area Control Error and the integrated value of which is treated as an Interchange Schedule for Interchange accounting purposes."[57]

Like Pseudo-Ties, Dynamic Schedules are expected to be tagged at the average MW profile for each 15-minute interval of the next scheduling hour as a single hourly value. These E-Tags must be submitted at least 20 minutes before the operating hour, and the transmission profile (described below) should reflect the expected maximum MW usage, for the Dynamic Schedule, for the hour. If the Dynamic Schedule or Pseudo-Tie is providing or bidding ancillary services the E-Tag must be submitted by 40 minutes before the operating hour.

Pursuant to NERC reliability standards and WECC Criterion, E-Tags for Dynamics Schedules also must be updated in certain circumstances:

- Where the average energy profile in an hour is greater than 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than ±10%.
- Where the average energy profile in an hour is less than or equal to 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than ±25 megawatt-hours.
- Where the Reliability Coordinator or Transmission Operator determines the deviation, regardless of magnitude, to be a reliability concern and notifies the Purchasing-Selling Entity of that determination and the reasons.
- Each hour of a dynamic schedule with the actual value within 60 minutes of the completion of the operating hour to allow for correct Net Scheduled Interchange between BAs.

---

[56] *See generally, CAISO*, 136 FERC ¶ 61,239 at P 2 (2011).

[57] Appendix A to the ISO tariff.

In any case, the Energy profile of the Dynamic Schedule must be updated with the final integrated Energy amount (MWh), as predetermined by a single, agreed-upon source, within 60 minutes after the completion of the Operating Hour.

Purchasing-Selling Entities/Scheduling Coordinators also must monitor Dynamic Schedule E-Tags for reliability curtailments and make adjustments to the dynamic signal accordingly. After a reliability curtailment has been initiated and subsequently released, they must release the reliability limit profile on the appropriate E-Tag at the time the reliability event allows for the reloading of the transaction, and without releasing the reliability limit of other Balancing Authorities and Transmission Service Providers. The existing level on the Interchange transaction E-Tag must not be greater than the most limiting reliability limit.

8.3 E-Tag Tools

The Western Interchange Tool (WIT) or successor electronic confirmation tool serves as the E-Tag authority in the WECC. The WIT is treated as the final record of Net Scheduled Interchange (NSI) and Net Actual Interchange (NAI) under normal operating conditions. In accordance with NERC standards, WIT receives requests for interchange (RFIs) via E-Tags from various entities and distributes these requests to reliability entities (balancing authorities and transmission service providers) and market entities for reliability and market assessments. WIT also confirms requests for interchange based on criteria set forth in NERC and WECC standards.

The ISO validates interchange transactions and confirms them with adjacent balancing authorities prior to implementing them as scheduled interchange. Additionally, the ISO assesses interchange transactions for reliability purposes, adequacy of transmission rights, and ensures market awards are not exceeded prior to E-Tag implementation. The ISO uses the interchange transaction scheduling software to process E-Tags, and when necessary, curtails/adjusts or denies E-Tags that do meet requirements.

The Interchange Transaction Scheduler (ITS) manages interchange transactions, provides Net Scheduled Interchange (NSI) to the ISO's energy management system (EMS) and real-time market. The interchange transaction scheduler also facilitates hourly NSI and Net Actual Interchange (NAI) checkout with adjacent Balancing Authorities (BA). In plain terms, the interchange transaction scheduler informs each balancing authority's systems on the expected net energy transfers across the interties. The individual and aggregate NSIs for each hour is based upon validated E-Tags.

8.4 What goes into an E-Tag?

This BPM cannot provide an exhaustive guide to submit E-Tags. Specific E-Tag requirements are subject to national (NERC and NAESB) and regional (WECC) standards, in addition to specific ISO requirements. Scheduling Coordinators seeking to schedule across interties should consult the following sources (as they are required to comply with them):

- NERC INT Reliability Standards
- WECC INT Regional Criterion
- NASEB Wholesale Electric Quadrant Standards
- NAESB Electronic Tagging Functional Specification
- ISO Operating Procedure 2510 (NERC Tagging Requirements)
- ISO Operating Procedure 2510A POR/POD Scheduling Path Cross Reference
- ISO Operating Procedure 4410 Emergency Assistance
- ISO Operating Procedure 4410D Emergency Assistance Resource IDs

While these sources comprehensively describe E-Tag requirements, generally the following information or headings appear on a typical E-Tag:

a) Tag Info: provides information about the Generator Control Area (GCA), the Purchasing Selling Entity (PSE), the tag code, the Load Control Area (LCA), the tag type (Transaction Type), the Time Zone of the tag, and MWh at the generation plant and at the destination load.

b) Market Path: provides information about the PSE, the Product, the Contract, and a Miscellaneous Information (Misc Info) field.

c) Physical Path: provides information on the proxy path of the power flow from the source Balancing Authority (BA) to the destination (sink) BA. This part of the tag includes information on the Transmission Service Provider (TSP), the Market Operator (MO), the Purchasing Selling Entity (PSE), the Point of Receipt (POR), the Point of Delivery (POD), the Scheduling Entities (SE), Contract if any, Miscellaneous Information (Misc Info) field and Loss columns.

d) Transmission Allocation: provides information about the TSP, the Owner, the Product, the OASIS information, NITS Resource, and Misc info field.

e) Transmission profile: provides information about the MW capacity amount of transmission reserved for the tagged transaction.

f) Energy profile: provides information about the MW amount of energy.

g) Loss Accounting: provides loss accounting

h) Carbon Copy List: provides a location for any entity to be copied on the E-Tag. Generally FERC is in this field.

i) Approval Status History: for the selected Request or all Requests if you are in the current state of the E-Tag. Provides information regarding the entities that took action on the creation of and changes on the E-Tag with a reason/comment. It also shows the exact time the action was initiated and what type of change took place. This is primarily automated.

j) Request Status: provides information on requests status and the timeline of each request.

k) Approval Status: provides the Approval Status History for all Requests in a single view and includes Timing information.

8.4.1 Valid Transmission and Energy Profiles

The E-Tag transmission profile is what the market participant has reserved, not necessarily the ISO transmission capacity the ISO market has awarded. The ISO market award is the transmission reservation the ISO market has awarded the SC on the intertie to transfer its energy. The MW value in the energy profile should equal the ISO market award and should not exceed the total MW value in the transmission profile.

The energy profile is the actual, expected MW value the market participant intends to flow, deliver, or receive. The energy profile should never be greater than the transmission profile because the market participant cannot flow more energy than they have reserved on the intertie. The energy profile should always be lower than or equal to the transmission profile. Scheduling Coordinators for dynamic resources and pseudo-tied generating units should avoid perfunctorily "maxing out" energy profiles to equal their transmission profiles or their generators' PMax. Doing so creates an unnecessary reservation on the interties that can present or exacerbate reliability and market issues. Energy profiles should always equal the resources' actual expected energy during the relevant interval.

Scheduling Coordinators also must update energy profiles on Dynamic and Pseudo-Ties after the relevant trading hour to equal the actual energy flow in MWh.[58] The PSE/Scheduling Coordinator E-Tags all dynamic schedules at the expected average MW profile for each 15 minute interval of the next scheduling hour, and then the PSE/Scheduling Coordinator updates the E-Tag with the actual value within 60 minutes of the completion of the operating hour. Section 1.5.6 of Appendix M of the ISO tariff reiterates this requirement, stating that a dynamic signal must be integrated over time by the Host Balancing Authority Area for every operating hour. All of these requirements are consistent with the most recent NAESB E-Tagging functional specifications.

8.4.2 Capacity Profile for Ancillary Services

Capacity E-Tags are treated differently than energy tags. Capacity tags have a valid transmission profile; however unlike energy E-Tags, capacity E-Tags do not have energy profiles until dispatched for energy in real time. Following the dispatch of capacity to energy the PSE/SC must immediately update the energy profile on the E-Tag to reflect the energy dispatch.

8.4.3 Scheduling Paths

The ISO market scheduling paths are associated with the market scheduling and intertie points. In most cases, the name registered in the NAESB Electric Industry Registry (EIR) provided by the OATI web Registry system is the same as the intertie point. WECC tagging specifications require a single point to be designated as point of receipt or delivery on E-Tags.[59]

8.4.4 Static Schedules or Normal E-Tags

For static schedules on normal type E-Tags a separate E-Tag must be submitted for each type of market award for energy, spin, or non-spin. Separate tags must be made for each of these product types to facilitate validation of tagged interchange with the respective market awards for energy, spinning reserves or non-spinning reserves. While a single market resource ID may be used to bid multiple market products into the ISO market on the interties, separate E-Tags are required to facilitate the validation process. The ISO's Interchange transaction scheduler compares the product type shown on the E-Tag, in the CAISO_PRODUCT Token/Value pair

[59] *See* https://www.naesbwry.oati.com/cgi-bin/webplus.dll?script=/NAESBWRY/sys-main.wml.

(ENGY, SPIN, or NSPN) with ISO market awards to validate each e-Tagged Interchange schedule. Only one product can appear on each E-Tag.[60]

When using a single Resource ID to schedule use of more than one type of transmission (for example use of both Energy Bid Curve and contract rights using a Contract Reference Number (CRN)), each transmission award must be separately tagged.[61] This situation can occur if energy is awarded to both an energy bid and the ETC, TOR, or CVR self-schedule with the MW allocation using a single resource ID. The responsible scheduling coordinator must submit two E-Tags, one for the energy bid award and one for the ETC/TOR/CVR award, each with the same resource ID.

8.5 Tagging and Validation Timelines

8.5.1 Tagging Validation and CAISO Market Awards

Approving an E-Tag does not guarantee a market award. In other words, there is not a causal relationship between interchange validation and market awards. E-Tag approval by the CAISO guarantees neither an CAISO market award nor a transmission reservation in the CAISO BAA. All market import or export interchange schedules are subject to final approval and transmission allocation in the CAISO markets. The CAISO will not auto approve E-Tags submitted after T-20 (i.e. less than 20 minutes before the start of the operating hour) but may manually approve such E-tags on a case-by-case basis. See CAISO operating procedure 2510 for tagging and validation rules.

Moreover, all interchange schedules are subject to approval by adjacent BAs and transmission providers. The interchange scheduler may curtail E-Tags due to reliability reasons or for violation of NERC, NAESB, WECC, or CAISO/BAA E-Tag requirements. Invalid E-Tags generally will be curtailed/adjusted to zero or denied.

Prior to the expiration of the reliability assessment period as defined in timing requirement tables in NERC Standard for Interchange Scheduling, the CAISO will respond to each on-time arranged interchange, emergency arranged interchange, and reliability adjustment arranged interchange to transition an arranged interchange to a confirmed interchange. If a reliability

---

[60] see the *Allowable Tag and Market Award Combinations* table at https://www.caiso.com/Documents/AllowableTag_MarketAwardCombinations.pdf. .

[61] System resources are selected from the drop-down menu in SIBR. They include, for example, resources with RA obligations, ETC/TOC contracts, certified to provide ancillary services, IBAA agreements for transmission loss adjustment, specific resource IDs, recirculating resource ID, losses, inadvertent payback, emergency assistance, MSS load following, and WEIM transfer schedules.

adjustment of arranged interchange is denied by the CAISO, the CAISO must notify the reliability coordinator within 10 minutes after the denial.[62]

If a reliability coordinator directs the modification of a confirmed interchange or implemented interchange for actual or anticipated reliability reasons, a reliability adjustment of the arranged interchange schedule must be submitted within 60 minutes of the start of the modification. Also, if a reliability coordinator directs the scheduling of interchange for actual or anticipated reliability reasons, an E-Tag must be submitted within 60 minutes of the start of the interchange schedule.

8.5.1.1 Day-Ahead and Real Time

It is highly recommended that Scheduling Coordinators tag their 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.

Tagging your final day-ahead Reliability Schedule 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 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

---

[62] These terms are defined by NERC and used throughout the industry. They are not defined terms under the ISO tariff. NERC defines Arranged Interchange as "The state where a Request for Interchange (initial or revised) has been submitted for approval;" Confirmed Interchange as "The state where no party has denied and all required parties have approved the Arranged Interchange;" Reliability Adjustment Arranged Interchange as "A request to modify a Confirmed Interchange or Implemented Interchange for reliability purposes;" Emergency as "Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System;" Implemented Interchange as "The state where the Balancing Authority enters the Confirmed Interchange into its Area Control Error equation." *See* http://www.nerc.com/files/glossary_of_terms.pdf.

[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.

Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined . . . ."

8.5.2 When to submit E-Tags

Upon receiving a CAISO real time market award on an intertie, the Scheduling Coordinator must submit an E-Tag to schedule the delivery of the energy or capacity award.

In addition to complying with all generally applicable E-Tagging requirements, Scheduling Coordinators must submit their E-tags consistent with the requirements specified in Section 30.6.2 of the CAISO tariff. If a Scheduling Coordinator receives an intra-hour Schedule change, then the Scheduling Coordinator must, by twenty minutes before the start of the FMM interval to which the Schedule change applies, ensure that an updated energy profile reflects the change. System shall send an explicit zero to market system for both hourly, 15-minutes and dynamic interties if the E-tag transmission profile is not present by T-40. The CAISO will not auto approve E-Tags submitted after T-20 (i.e. less than 20 minutes before the start of the operating hour) but may manually approve such E-tags on a case-by-case basis.

8.5.2.1 Hourly bid option intertie resources

As further detailed in section 30.5 of the ISO tariff, Scheduling Coordinators must submit E-Tags by 40 minutes prior to the applicable Trading hour for the following bid types to avoid market consequences defined in section 30.5:

- Self-scheduled hourly block
- Self-scheduled Variable Energy Resource
- Economic hourly block bid
- Economic hourly block single change bid

8.5.2.2 15-minutes bid option intertie resources

By 40 minutes prior to the applicable Trading Hour, the Scheduling Coordinator must submit an E-Tag (or set of E-Tags) that passes CAISO E-Tag validation procedures and that supports the FMM Economic Bid. If the Scheduling Coordinator fails to submit a valid E-Tag by forty minutes prior to the applicable Trading Hour, then the CAISO will set the MW quantity of the FMM Schedule associated with the FMM Economic Bid to zero for each FMM interval of the hour. The transmission profile of the E-Tag at forty minutes prior to the applicable Trading Hour must be greater than or equal to the FMM Economic Bid. If the Scheduling Coordinator has a transmission profile less than its advisory Energy schedule, then the CAISO will limit the schedule for Energy in the FMM so that it does not exceed the quantity of the transmission profile.

The energy profile of the E-Tag at forty minutes prior to the applicable Trading Hour need not equal the FMM Economic Bid and the Scheduling Coordinator may revise the Energy profile up to twenty minutes prior to the applicable Trading Hour. At twenty minutes prior to the applicable Trading Hour the quantity of the energy profile must be equal to the lower of: (a) the transmission profile of the E-Tag at forty minutes prior to the applicable Trading Hour; or (b) the quantity of the FMM energy schedule for the first FMM interval of the applicable Trading Hour.

The CAISO may modify the Energy profile due to Reliability related curtailments.

Scheduling Coordinators with cleared FMM Economic Bids may update either the transmission profile or the Energy profile after forty minutes prior to the applicable Trading Hour and twenty minutes prior to the applicable Trading Hour, respectively. A Scheduling Coordinator choosing to update the transmission profile must submit an updated transmission profile at least 40 minutes prior to the applicable FMM interval. A Scheduling Coordinator choosing to update the Energy profile must submit an updated Energy.

8.5.3 E-Tag Adjustments and curtailments

ISO market-automated E-Tag adjustment applies to all E-Tags and is performed based on bid type. The ISO market does not adjust E-Tags when it is not the Transmission Service Provider (TSP) or the Market Operator (MO) on the E-Tag. The ISO notes that E-Tag curtailments are mostly performed during abnormal system conditions that may require operator action to bring the system to a reliable state. See CAISO operating procedure 2510 for rules on adjustments and curtailments.

- For hourly block bids, the relevant E-Tags are adjusted down at T-40 when the MW value of the relevant market award from HASP is below the energy profile in the E-Tag.

- For fifteen-minute bids, the relevant E-Tags are adjusted up or down at T-40 for all four fifteen minutes intervals to match the HASP market advisory awards. And at the publication of each binding fifteen minutes awards, these E-Tags are adjusted again if the binding award for the relevant FMM interval is different from the previously published advisory awards.

    - System shall determine the 15-minute binding award for hourly intertie resources based on the E-Tag at T-40. The 15-minute market binding award

for hourly interties shall equal the lower of the HASP schedule, HASP accepted award (ADS accepted value), or E-Tag transmission profile

- For 15-minutes bid opted intertie resources, E-Tag with valid transmission profile is due by T-40.

- For dynamic bids that are *not* WEIM transfers (ETSRs), the relevant E-Tags are not currently adjusted by the ISO market systems. These E-Tags are adjusted after-the-fact by the PSE or the Scheduling Coordinator within sixty minutes of the end of the relevant hour, consistent with NERC standards.

- For fifteen minute ETSRs for transactions between the ISO BAA and another WEIM BAA, the relevant E-Tags are adjusted:

  - Near the top of the hour to match the average of the advisory awards from HASP.

  - Up or down at T-40 for all four fifteen minutes intervals with the market advisory awards if the advisory is different from the previously published average MW.

  - At the publication of each binding fifteen minutes award, if the binding award for the relevant FMM interval is different from the previously published advisory awards from HASP.

- For five minute (dynamic) ETSRs for transactions between the ISO BAA and another WEIM BAA, the relevant E-Tags are adjusted:

  - Near the top of the hour to match the average of the advisory awards from HASP. These E-Tags are adjusted again by the PSE or the Scheduling Coordinator within sixty minutes of the end of the relevant hour, consistent with NERC standards.

- E-Tags are also adjusted or curtailed based on CAISO Market Priority Type DAPT, DALPT, RTPT, RTLPT, RTECON. Scheduling coordinators are required to enter in the E-Tag Market Path G-FP (Generation-Firm Provisional) in "Product" field for all CAISO low Market Priority Types (i.e., DALPT, RTLPT, RTECON). In an EEA3 condition, where armed load is utilized to restore deficient contingency reserves, lower priority exports E-Tags curtailments may be used in order to maintain required contingency reserves.

❖ **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.

8.5.4 EIM Transfers

EIM transfers are called Energy Transfer System Resources (ETSRs). They can be static (15 min resources on normal type E-Tags) or dynamic (5 min resources on dynamic type E-Tags). Please see the *BPM for Western Imbalance Energy Market* for further details.

8.6 Emergency and Contingency Events

During emergency conditions, specific emergency intertie resources are pre-registered in the ISO Master File to record transfer of the energy. Please see ISO Operating Procedure 4410D, Emergency Assistance Resource IDs for the pre-registered emergency resource IDs. The tagging must be done following the tagging rules outlined in ISO Operating Procedure 4410, Emergency Assistance. Contingency events are not any different when it comes to the market awards and tagging ISO market awards requirements. In accordance with reliability standards, the ISO and all balancing authorities will either approve or deny arranged interchange requests received based upon reliability considerations. Additionally balancing authorities will implement confirmed interchange received, and sending and receiving balancing authorities will agree to interchange prior to implementing it in their ACE equation.

The emergency type tag shall only be used for E-Tags at the request of the Interchange Scheduler or in response to an operational message from the ISO. The ISO may request use of an emergency E-Tag type in the event an import or export schedule is required after normal scheduling timelines and the transaction is in response to a loss of transmission facility, potential reserve or energy deficiency, or to supply or receive emergency assistance from another BAA during a contingency event. The emergency type tag is not used nor requested by the ISO for economic purposes or to expedite approval for a market transaction or for a late E-Tag under non-emergency or non-potential emergency events. Emergency type E-Tags will not be approved by the ISO outside of an emergency or potential emergency event.

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)

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 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. 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.

9. Post Market Activities

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

- How CAISO validates LMPs
- How CAISO applies administrative prices

9.1 Price Validation

The CAISO has authority under the MRTU Tariff, to correct prices to ensure that settlement is consistent with the Tariff. CAISO shall make reasonable efforts to ensure that LMPs published

to OASIS and through the Customer Market Results Interface (CMRI), and ultimately used for settlement and billing, are calculated accurately and reflect all pertinent operational data and system conditions, and are consistent with CAISO Tariff provisions. CAISO shall continuously monitor all market clearing software solutions to identify anomalous resource commitment, dispatch levels, and prices that may have resulted from erroneous input data and/or hardware/software failure of the market applications. All markets in Day-Ahead and Real-Time shall be subject to this Market Validation process. Although the CAISO will make every effort to validate market clearing processes and results prior to publication of results, this will not always be the case, particularly for Real-Time markets.

This market validation effort can be viewed as a two phase process:

- Phase I: Market Validation

  There is a small window of opportunity to validate the market results before they are published to OASIS and CMRI. This window is different for each market. The Day-Ahead Market allows more time to validate market outcomes before publishing results. Thus, CAISO expects that invalid Day-Ahead Market result publication to OASIS and CMRI would be unlikely. On the other hand, for the Real-Time Market, the 5-minute dispatch interval timeline provides CAISO analysis limited opportunity to identify and resolve invalid market data or solutions before publication of the invalid market prices. In either case, when prices are determined to be invalid after they are published to OASIS, they would be corrected following the price correction process described below.

- Phase II: Price Corrections

  The price correction process is an off-line analysis that occurs after the Market results are published to OASIS and sent to Market Participants through the CMRI. The purpose of the validation is to identify and correct prices in any periods with error conditions or incorrect results. The price validation process ensures that the LMPs used for Market Settlement are based on the proper data, and that the Market solution accurately reflects the power system conditions and CAISO Operator actions that should have been considered in the relevant Market process. This post-publication market validation process is completed within a prescribed window of time following each market. All prices published on OASIS or in other sources are subject to potential correction during the prescribed price correction window. All prices are considered final after the prescribed price correction window has expired.

9.1.1 Market Validation

For all CAISO Markets, CAISO shall closely monitor results, and if time permits, correct problems and re-run the market as necessary to minimize the number of post-publication price corrections. The short timeline of the Real-Time Market may prevent the re-running of the market for the current interval in most cases, but correcting any issues immediately serves to minimize the number of intervals affected by the problem going forward, and thus minimize the post-publication price corrections.

9.1.2 General Scope of Price Corrections

Prices may be corrected when (i) a market solution is determined to be invalid, or (ii) invalid prices are identified in an otherwise valid market solution. The following are some reasons that may be the causes of these conditions:

- Data Input failure. Missing or incorrect versions of one or more data elements input to the market applications may result in an invalid market solution and/or prices. State Estimator data, in particular, may be a cause of Real-Time Market validation problems, and will be a focus of the validation effort.

- Hardware/Software failure. While CAISO has designed a very high degree of reliability into the CAISO Market systems' architecture, the market run may fail to yield a converged solution in all executions. This may be due to hardware or software failure, planned market systems outages, or simply a failure of the Security Constrained Unit Commitment (SCUC) optimization software to converge. In any case, such events result in an invalid or non-existent market solution, for which corrected prices will be determined after-the-fact, per Section 8.1.4 below.

- Inconsistency with Tariff. A third category of invalid market solution or incorrect price calculations is related to the correct application of market rules, per CAISO Tariff. Market results will be validated to be consistent with CAISO Tariff, and where applicable, prices may be corrected to meet this goal. This includes, but is not limited to ensuring that (i) price setting resources are eligible to do so, and (ii) binding constraints are applied (or relaxed) in the appropriate priority order.

Section 35.3 of CAISO Tariff provides additional details regarding the basis for price corrections.

Following are some qualifications to the scope of price corrections:

- Price anomalies, or price spikes, due to scarcity of resource bids will not be a cause for price corrections.

- The extent to which bids are mitigated in the MPM process has a direct impact on the market clearing prices in the IFM or RTM. Therefore, these SCUC solutions will be subject to market validation principles. However, it should be noted that prices resulting from the MPM SCUC passes are not themselves validated, as these prices are not used for settlement.

- Advisory HASP prices are not in scope for price correction.

- Prices for Exceptional Dispatch instructions will not be subject to the price correction framework, as they will not be the output of the market engine.

- Hourly weighted average LMP's and 10-minute settlement prices will be corrected, as applicable, when 5-minute RTED prices are corrected. These prices are not directly subject to the price correction process, but will remain synchronized with the validated 5-minute prices as they are systematically derived by the corrected 5-minute prices.

- If CAISO corrects a PNode price, it will update the corresponding LAP / Trading Hub prices accordingly.

9.1.3 Scope of Price Corrections for DAM

The CAISO will validate all commitment decisions, dispatch levels, and prices to be consistent with bids, market rules, and system conditions. In this validation process, the CAISO will evaluate the integrity of all market inputs and results. When a market solution is determined to be invalid, prices will be corrected as necessary, and the affected public market information re-posted to OASIS.

Specifically, the following elements are in scope for the Day-Ahead Market price corrections:

- Final Hourly LMPs for all Pricing Nodes (PNode) and Aggregated Pricing Nodes (APNode)

- Marginal energy cost component

- Marginal congestion cost component

- Marginal loss cost component

- Final Hourly ASMPs for all PNodes

- Final hourly transmission constraint shadow prices at each transmission interface

9.1.4 Scope of Price Corrections for RTM

Specifically, the following elements are in scope for RTM price corrections:

- Binding FMM Prices. 15-minute binding LMPs, ASMPs, and transmission constraint shadow prices, including each of the three cost components, are subject to the price correction process.

- Real Time Economic Dispatch. 5-minute binding LMPs, including each of the three cost components, for all PNodes and APNodes are subject to the price correction process.

- Transmission and Intertie constraint shadow prices. 5-minute transmission constraint shadow prices at each transmission interface will be validated and subject to price correction.

9.1.5 Price Correction Process

The price correction process starts with a validation of all prices indicated above in Sections 8.1.3 and 8.1.4 for a given Trading Day, beginning immediately after prices are available, and ending after the Price Correction Time Horizon (defined in section 8.1.6.2, below) has closed for that Trading Day to identify if any corrections are necessary. The intent of the validation process is to ensure appropriate and accurate inputs are used in Settlements as well as to ensure prices accurately reflect system conditions.

Where feasible and practical, the CAISO will correct invalid prices to conform to the relevant CAISO Tariff provisions. Where this is neither feasible nor practical, the CAISO will correct prices as close as reasonably possible to the price that should have resulted under the CAISO Tariff provisions, using the most accurate data available, and in a manner that is consistent with the prevalent system conditions at that time. The CAISO will use one of the following methods, as appropriate, with respect to the nature of the invalid price conditions.

The order of the price correction methods listed below are shown in order of preference from most preferred to least preferred. When correction of prices can be done on isolated pricing locations or resources without impacting the over-all market solution, this method is preferred. If this is not possible, the preferred price correction method is to re-run the affected markets, with the root cause of the invalidation corrected. However, this may not always be feasible due to unrecoverable data loss, or may not always be practical within the Price Correction Time Horizon. In these situations, interval or solution replication will be used.

9.1.5.1 Isolated Price Corrections

When possible, the CAISO will selectively recalculate invalid PNode and APNode prices, such that the market optimization need not be re-run. This method can only be used when invalid prices are isolated and when corrections can be made such that no other market clearing prices are affected by the correction.

9.1.5.2 Market Re-Runs

A market solution may be determined to be wholly invalid because of hardware or software failure, incorrect data or solution parameters, or any other factor that affects system wide results. When such a market solution is identified, the CAISO will attempt to recreate a valid SCUC solution for the affected market run. When the source of the problem is incorrect data, the market re-run will use as much validated data as possible from the original market run. To replace the problematic data, CAISO will either (i) restore the correct data when possible, or (ii) recreate or replicate data using the best available alternate data sources.

9.1.5.3 Replicate Prices from Validated Market Intervals – Day-Ahead Market

If the entire market solution is deemed to be invalid then all prices will be corrected using the re-run method specified above. In no cases will an invalidated Day-Ahead Market solution be replaced with a valid Day-Ahead Market solution from a previous Trading Day.

Interval replication shall only apply in Day-Ahead Market when some but not all hourly intervals within a valid market run are deemed to be invalid and the market is not rerun as explained above. This condition is expected to be rare. In such a case, prices for an invalidated interval shall be replicated from prices for a validated interval that best represents the market conditions in the invalid interval. This will be an adjacent interval in most cases.

9.1.5.4 Replicate Prices from Validated Market Intervals – Real-Time Market

Price replication in Real-Time Markets will only be under taken when both isolated price correction and market re-run actions are (i) not feasible because of CAISO's inability to generate a reasonably accurate set of input data or the security constrained unit-commitment or security constrained economic dispatch processes cannot find a feasible solution, or (ii) not practical from the perspective of validating all prices within the Price Correction Time Horizon.

For the source of replicated prices, the CAISO may use prices from validated intervals within the same market solution, similar to that which is described above or prices from a previous or subsequent market solution. When prices are replicated from a previous or subsequent market solution, the replicated prices may be either binding or advisory prices. The selection of the

source market solution and specific interval for price replication shall be based on the best representation of the market conditions for the invalidated interval.

The following are some details of the RTM price replication methodology:

- For RTED (including RTCD) FMM energy prices, FMM, ASMP, and FMM flexible ramping constraint shadow prices source market intervals for price replication shall be taken from a market solution within the same Trading Hour as the invalid market interval for bid consistency, when possible. If this is not possible the analyst will replicate prices from an interval in an adjacent Trading Hour that best resembles the market conditions of the invalidated market run.

- For Short Term Unit Commitment (STUC), the advisory prices for 15-minute intervals are not in-scope for price corrections.

- For RTED, prices may be replicated from the most representative market solution, and may be from a similar RTED market run including advisory solution for the same time interval from previous RTED runs, or from a similar 15-minute FMM run.

9.1.6 Procedures

9.1.6.1 Publication

All prices published to OASIS and reported to Market Participants through CMRI are considered provisional until the validation and Price Correction Time Horizon is completed. If a price correction is needed for a particular trade day and that correction cannot be made within the prescribed Price Correction Time Horizon due to processing and publication issues then the CAISO shall provide notice to market participants through OASIS about the delay of the processing and publication of corrected prices.

9.1.6.2 Price Correction Time Horizon

The CAISO will begin validating market prices immediately upon publication of results for all market runs. The price validation process for a given Trading Day will conclude in a number of days after the Trading Day, as described below. The period between the end of the Trading Day and the end of the price validation process is called the Price Correction Time Horizon. All prices for a given Trading Day are subject to validation and possible price correction until such time as (i) the Price Correction Time Horizon has ended for that Trading Day, or (ii) CAISO has published a notice to its website that the validation process for the Trading Day is concluded.

The CAISO will inform the market through an OASIS message about price corrections as soon as practical within the proposed three business day window for the day-ahead market and the

five business days for the real time market. If such notice is not published on OASIS before the end of the Price Correction Time Horizon for a Trading Day, then such notice is implied by the expiration of the Price Correction Time Horizon, and no further validation or price corrections will occur for the Trading Day. The CAISO will not make any price corrections after the Price Correction Time Horizon has expired except as otherwise directed by the Federal Energy Regulatory Commission.

The CAISO will evaluate the length of the Price Correction Time Horizon annually.

- The Price Correction Time Horizon is three business days for the Day Ahead Market, and five business days for Real-Time Market, meaning that the Price Correction Time Horizon shall begin at the time of publication of market prices to OASIS for the Trading Day, and shall end at 23:59 on the third or fifth business day, as applicable following that Trading Day.

In the event that the CAISO experiences a processing or publication issue which renders the prices posted on OASIS or CMRI inconsistent with any price that was subject to a price correction, the ISO shall endeavor to correct such publication as soon as practicable. Twenty business days after the applicable Trading Day, the CAISO will not correct such processing or publication errors except as otherwise directed by the Federal Energy Regulatory Commission. After twenty business days, if there is still a discrepancy between the published prices on OASIS or CMRI and the prices used for settlements, in the event of a valid settlement dispute the CAISO will adjust the settlement prices to reflect the prices posted on OASIS for the applicable intervals.

9.1.6.3 Reporting

The CAISO will summarize all price corrections in a report and publish the report on the CAISO website. For each instance of market price correction, the weekly report shall contain:

- Brief description of the root cause of market invalidation
- Affected market intervals
- Affected price locations
- Method of Price Corrective action(s) taken

For illustrative purposes below is a sample of the timeline for generating the weekly price correction reports:

Calendar Date and Day: The "Calendar Date" and "Day" columns show the specific day on which the CAISO publishes the report on OASIS. For example, 4/1/2024, falls on a Monday.

- **IFM Trade Dates (T+3B)**: This column refers to the dates of the IFM that are corrected and published after T+3B. For instance, on 4/1/2024, the CAISO would report IFM price correction for 3/27/2024.
- **RT Trade Dates (T+5B)**: This column refers to the dates for RT prices that are corrected and published after T+5B. On 4/1/2024, the report would include price corrections for 3/25/2024.
- **OASIS Price Correction Report Period**: This column summarizes which IFM and RT dates are included in the OASIS report for the corresponding calendar day. For example, on 4/1/2024 (Monday), the report would cover IFM corrections for 3/27 and RT corrections for 3/25.

The CAISO does not publish price correction reports on weekends

Calendar Date	Day	IFM Trade Dates (T+3B)	RT Trade Dates (T+5B)	OASIS Price Correction Report Period
01-Apr-24	Monday	3/27/2024	3/25/2024	IFM: 3/27, RT : 3/25
02-Apr-24	Tuesday	3/28/2024	3/26/2024	IFM: 3/28, RT : 3/26
03-Apr-24	Wednesday	3/29/2024-3/31/2024	3/27/2024	IFM: 3/29-3/31, RT : 3/27
04-Apr-24	Thursday	4/1/2024	3/28/2024	IFM: 4/1, RT : 3/28
05-Apr-24	Friday	4/2/2024	3/29/24-3/31/24	IFM: 4/2, RT : 3/29-3/31
06-Apr-24	Saturday	N/A	N/A	N/A
07-Apr-24	Sunday	N/A	N.A	N/A
08-Apr-24	Monday	4/3/2024	4/1/2024	IFM: 4/3, RT : 4/1
09-Apr-24	Tuesday	4/4/2024	4/2/2014	IFM: 4/4, RT : 4/2

The OASIS report will not contain “before and after” data for price corrections. Once the CAISO replaces invalid prices with corrected prices OASIS will not make invalid prices available. Note that OASIS does provide data versioning functionality, which allows Market Participants to identify which data points have been updated during the price correction process, and also can be set to notify Market Participants when updates occur.

9.2 Administrative Pricing

The CAISO has authority under the CAISO Tariff, to apply administrative prices under certain conditions. The administrative pricing implementation in the CAISO markets uses a tiered

approach depending on the market and the length of the disruption period. The CAISO experiences minor market disruptions in the real-time market due to software maintenance (such as database updates and software releases) or unexpected software issues, and these occur under both normal and non-emergency situations. The CAISO can also intervene in the CAISO markets during system emergencies or to prevent system emergencies, and suspend or disrupt the market and operate the system manually. The administrative pricing can apply to any market or product, including the day-ahead market, fifteen- and five-minute markets.

9.2.1 Administrative Pricing for Day-Ahead Market

The target publication time for the day-ahead market is 1:00 p.m. The CAISO generally is able to publish on time, but in some scenarios it may delay the publication of results to resolve a specific issue. This usually may require a late publication that is not far from the ideal time. However, in the extreme case where the CAISO has not published the day-ahead market results or determines it may suspend the day-ahead market, it will notify market participants by 6:00 p.m. of the CAISO decision. The notification to the market will be through a market notice, and will be in addition to any updates provided through the operational messages during the course of the event. This approach is to provide market participants with the best available information by 6:00 p.m., including whether the CAISO anticipates that it will be able to publish market results. This will allow market participants to know their schedules and have enough lead time to meet their resource commitment instructions with sufficient advance notice. In cases where commitments and dispatches are not feasible to happen by the time the day-ahead results are published, the ISO may be required to use exceptional dispatches. The alternatives that the CAISO can use are:

(i) **Late publication of the day-ahead market results**: If the CAISO has addressed the issues causing the problem, the CAISO will inform market participants of its decision and the likely time-frame for publication. The CAISO's preference will be to publish the day-ahead market for the day even if it is a late publication because ti will be the most accurate solution.

(ii) **Use the previous day's market results for the day-ahead market**. There are several reasons why this can be a workable alternative in the event the CAISO day-ahead market results are not available. First, using the previous day's market results will mitigate against the worst-case scenario in which the real-time market might also need to be suspended. Second, using the previous day's market results will provide the CAISO with a starting point for dispatch and settlement, while the real-time market can provide the incremental or decremental differences between the day-ahead and the real-time, thereby

minimizing the need for the CAISO to issue manual dispatch instructions. Third, using the previous day's market results will allow market participants to know in advance their market results for the applicable trading day, which will minimize uncertainty and allow market participants to secure fuel and prepare their resources for unit commitment. Congestion revenue rights will settled as usual using prices from the previous day-ahead market because the energy market will still be settled at the day-ahead prices. However, if the CAISO decides to use the day-ahead market results from the previous day for the day-ahead market, it will suspend any virtual bids for that day and settle only physical bids using the day-ahead market results from the previous day.

(iii) **Rely solely on real-time market results and exceptional dispatch**. If the CAISO decides to rely solely on the results of the real-time market for pricing and settlement purposes, then there will be no virtual awards to settle. Congestion revenue rights will be settled on hourly prices estimated as the simple average of the four fifteen-minute market prices.

9.2.2 Administrative Pricing for Real-Time Market

The administrative pricing logic is defined for both the fifteen- and five-minute markets. The rules for administrative pricing also depend on whether the real-time market is suspended or not. For conditions in which the market has not been suspended, the rules are defined based on the length of the disruption.

i) **Disruption lasting less than an hour**.
   a. If market results are unavailable for fewer than four consecutive 15-minute intervals in the fifteen minute market, the CAISO will use the fifteen-minute market prices, as applicable, for the fifteen-minute interval immediately preceding the fifteen minute market interval(s) for which fifteen minute market results are unavailable.
   b. If prices are unavailable for fewer than 12 consecutive five-minute dispatch intervals, the CAISO will use the real-time dispatch market prices, as applicable, for the dispatch interval immediately preceding the dispatch interval(s) for which market results are unavailable.

ii) **Disruption lasting an hour or longer in one of the two real-time markets**.
   a. If market results are unavailable for at least four consecutive fifteen-minute intervals in the fifteen minute market, but market results are available for the real-time dispatch during those fifteen-minute market intervals, the CAISO will use the average of real-time dispatch market results, as applicable, during each such

fifteen minute market interval and use the market results as applicable from the prior intervals for which market results are unavailable as needed; and

b. If market results are unavailable for at least 12 consecutive five-minute dispatch intervals, but market results are available for the fifteen minute market during those dispatch intervals, the CAISO will use the fifteen minute market results, as applicable, from the applicable fifteen minute market during the dispatch intervals

iii) **Disruption lasting an hour or longer for both the fifteen-minute market and the real-time dispatch**.

a. If market results are unavailable for at least four consecutive fifteen-minute intervals in the fifteen minute market and for the real-time dispatch during those fifteen-minute market intervals, the CAISO will use the day-ahead market results, as applicable, for the corresponding trading hour for which market results are unavailable; and

b. If market results are unavailable for at least 12 consecutive five-minute dispatch intervals and for the fifteen-minute market during those dispatch intervals, the CAISO will use the day-ahead market results, as applicable, for the corresponding trading hour for which market results are unavailable

Examples:

The following table illustrates two hours of the market with all prices available:

Hour Ending	13												14											
FNM Interval	1	1	1	2	2	2	3	3	3	4	4	4	1	1	1	2	2	2	3	3	3	4	4	4
RTD Interval	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
DAM Price	40												50											
FNM Price	48	48	48	50	50	50	51	51	51	40	40	40	45	45	45	39	39	39	53	53	53	60	60	60
RTD Price	44	46	47	47	70	65	65	62	60	59	59	55	35	36	38	39	44	43	43	48	50	55	57	59

Scenario 1: five-minute prices are missing for five intervals as highlighted in the entries in yellow in the first table, per current logic, use last available five-minute price (green entry); this will result with the prices shown in the second table

Hour Ending	13												14											
FNM Interval	1	1	1	2	2	2	3	3	3	4	4	4	1	1	1	2	2	2	3	3	3	4	4	4
RTD Interval	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
DAM Price	40												50											
FNM Price	48	48	48	50	50	50	51	51	51	40	40	40	45	45	45	39	39	39	53	53	53	60	60	60
RTD Price	44	46	47	47	70	65	65	62						36	38	39	44	43	43	48	50	55	57	59

Hour Ending	13												14											
FNM Interval	1	1	1	2	2	2	3	3	3	4	4	4	1	1	1	2	2	2	3	3	3	4	4	4
RTD Interval	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
DAM Price	40												50											
FNM Price	48	48	48	50	50	50	51	51	51	40	40	40	45	45	45	39	39	39	53	53	53	60	60	60
RTD Price	44	46	47	47	70	65	65	62	62	62	62	62	62	36	38	39	44	43	43	48	50	55	57	59

Scenario 2: Both fifteen-minute and five-minute prices are missing, each one, for less than twelve and four intervals, respectively. Per current logic, CAISO uses the last available price for each market as shown in the second table:

Hour Ending	13												14											
FNM Interval	1	1	1	2	2	2	3	3	3	4	4	4	1	1	1	2	2	2	3	3	3	4	4	4
RTD Interval	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
DAM Price	40												50											
FNM Price	48	48	48	50	50	50				40	40	40	45	45	45	39	39	39	53	53	53	60	60	60
RTD Price	44	46	47	47	70	65	65							36	38	39	44	43	43	48	50	55	57	59

Hour Ending	13												14											
FNM Interval	1	1	1	2	2	2	3	3	3	4	4	4	1	1	1	2	2	2	3	3	3	4	4	4
RTD Interval	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
DAM Price	40												50											
FNM Price	48	48	48	50	50	50	50	50	50	40	40	40	45	45	45	39	39	39	53	53	53	60	60	60
RTD Price	44	46	47	47	70	65	65	65	65	65	65	65	65	36	38	39	44	43	43	48	50	55	57	59

Scenario 3: If five-minute prices are missing for at least twelve intervals and fifteen-minute prices are available, then CAISO uses the fifteen-minute prices for the corresponding five-minute intervals:

Hour Ending	13												14											
FNM Interval	1	1	1	2	2	2	3	3	3	4	4	4	1	1	1	2	2	2	3	3	3	4	4	4
RTD Interval	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
DAM Price	40												50											
FNM Price	48	48	48	50	50	50	51	51	51	40	40	40	45	45	45	39	39	39	53	53	53	60	60	60
RTD Price	44	46	47	47	70	65	65	62															57	59

Hour Ending	13												14											
FNM Interval	1	1	1	2	2	2	3	3	3	4	4	4	1	1	1	2	2	2	3	3	3	4	4	4
RTD Interval	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
DAM Price	40												50											
FNM Price	48	48	48	50	50	50	51	51	51	40	40	40	45	45	45	39	39	39	53	53	53	60	60	60
RTD Price	44	46	47	47	70	65	65	62	51	40	40	40	45	45	45	39	39	39	53	53	53	60	57	59

Scenario 4: If fifteen-minute prices are missing for four or more intervals, then CAISO uses the simple average of the three five-minute prices for the corresponding intervals:

Hour Ending	13												14											
FNM Interval	1	1	1	2	2	2	3	3	3	4	4	4	1	1	1	2	2	2	3	3	3	4	4	4
RTD Interval	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
DAM Price	40												50											
FNM Price	48	48	48																53	53	53	60	60	60
RTD Price	44	46	47	47	70	65	65	62	60	59	59	55	35	36	38	39	44	43	43	48	50	55	57	59

Hour Ending	13												14											
FNM Interval	1	1	1	2	2	2	3	3	3	4	4	4	1	1	1	2	2	2	3	3	3	4	4	4
RTD Interval	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
DAM Price	40												50											
FNM Price	48	48	48	60.6	60.6	60.6	62.3	62.3	62.3	57.6	57.6	57.6	36.3	36.3	36.3	42	42	42	53	53	53	60	60	60
RTD Price	44	46	47	47	70	65	65	62	60	59	59	55	35	36	38	39	44	43	43	48	50	55	57	59

Scenario 5: If both fifteen-minute and five-minute prices are missing for at least four and twelve intervals, respectively, then CAISO uses DAM prices for the trade hours corresponding to the RTM disruptions:

Hour Ending	13												14											
FNM Interval	1	1	1	2	2	2	3	3	3	4	4	4	1	1	1	2	2	2	3	3	3	4	4	4
RTD Interval	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
DAM Price	40												50											
FNM Price	48	48	48	50																		60	60	
RTD Price	44	46	47	47																		57	59	

Hour Ending	13												14											
FNM Interval	1	1	1	2	2	2	3	3	3	4	4	4	1	1	1	2	2	2	3	3	3	4	4	4
RTD Interval	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
DAM Price	40												50											
FNM Price	48	48	48	50	40	40	40	40	40	40	40	40	50	50	50	50	50	50	50	50	50	50	60	60
RTD Price	44	46	47	47	40	40	40	40	40	40	40	40	50	50	50	50	50	50	50	50	50	50	57	59

There is also a specific rule for administrative pricing when the real-time market has been suspended. In such instances, the CAISO will use the previous day's day-ahead market

results, as applicable, for the trading hour corresponding to the trading hour during which the real-time market has been suspended. Applying day-ahead market results in this manner will provide price certainty and transparency to market participants.

Finally, in the event administrative pricing logic does not apply in a given situation, the administrative price will be the price established for that product or service immediately prior to the disruption.