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Common Acronyms Used Within this Document

- Ancillary Services = A/S
- Automated Dispatching System = ADS
- Available Transfer Capability = ATC
- Billable Quantity = BQ
- Charge Type = CT
- Day Ahead = DA
- Hour Ahead = HA
- Instructed Imbalance Energy = IIE
- Local Market Power Mitigation = LMPM
- Market Clearing Price = MCP
- Market Redesign and Technology Upgrade = MRTU
- Megawatt = MW
- Megawatt Hour = MWh
- Minimum Dispatchable Level = MDL
- New Firm Use = NFU
- Non-Spinning Reserve = NSPIN
- Out of Sequence = OOS
- Real Time = RT
- Residual Instructed Energy = RIE
- Residual Uninstructed Energy = RUE
- Resource Data Template = RDT
- Scheduling Coordinator = SC
- Spinning Reserve = SPIN
- Supplemental Energy = SUPP
- Transmission Owner = TO
Ancillary Services

Q: (CT 111): If both the DA and HA SPIN Market Clearing Price were not zero for the hours in dispute, shouldn’t I see a non-zero price in my CT 111 since it’s a weighted average price for DA and HA SPIN costs?

A: Not necessarily. The procurement price in a region is different from the MCP for that service. For the calculation of the procurement cost you need the non Self-Provided procurement MW amount multiplied by the MCP. If no MWs were procured, there would be no procurement cost, making the price of procurement $0.00.

Additionally, the revenue from CT 111 pays for Capacity payments made to SCs with awarded non Self-Provided capacity, or those the CAISO procured MWs. The total quantity procured is calculated by:

\[
\text{Sum of (DA non Self-Provided} + (\text{HA incremental non Self-Provided} - \text{Buy Backs}),}
\]

where \(\text{Buy Back} = (\text{DA Self-Provided} - \text{HA Self-Provided})\)

At times the above equation results in a negative procurement quantity. For example: If the DA procurement was 0 (entirely Self-Provided) and the HA procurement was 20, but the Buy Back amount is 30, then procurement amount is \((0 + 20 - 30)\) which equals -10.

It is not possible to procure a negative amount of capacity. Therefore, any negative procurement quantities reset to 0 for the CT 111 price calculation.

Interzonal Congestion

Q: Why did I receive DA congestion charges when no congestion actually occurred in Real Time?

A: The CAISO manages and settles congestion in each Market (DA, HA and RT) separately. The CAISO runs its Congestion Management software to determine if there is congestion in the DA and HA Markets, adjusts schedules to mitigate transmission congestion, and establishes a usage charge or “toll” that is applied to those schedules that remain on congested interfaces. Usage charges that are applied to a SC’s DA and/or HA schedules represent the cost of remaining scheduled on the line
in that particular Market, and is applied regardless of whether congestion occurs in a subsequent Market.

Q\textsubscript{2a} (CT 253): How can I be receiving congestion charges when I have no schedules crossing zones?

A\textsubscript{2a} — The congestion Billable Quantity (BQ) is based upon the \textit{sum of net import into or export from a zone}. Import and Export Intertie schedules are explicit schedules across zones. There are also implicit schedules that cross zonal interfaces and may receive congestion charges. Implicit schedules are scheduled energy that crosses zones internal to the CAISO Control Area, between North Path 15 (NP15), Zone Path 26 (ZP26) and/or South Path 15 (SP15). These schedules are not actually scheduled at the interconnection point between these zones (as Import and Export schedules are). Rather, the energy is implicitly scheduled in or out of the zone based on how the SC has scheduled its portfolio.

For example, if a SC has 50 MW of load and 40 MW of generation in NP15 and no other schedules in NP15, then 10 MW is coming into the zone to supply the load schedule. The 10 MW is an implicit schedule if it is being supplied by either ZP26 or SP15, or if the energy is being imported on an Intertie and must pass through one of those zones to get to NP15.

Q\textsubscript{2b} (CT 253): What if my net schedule was balanced within a zone in the scenario above?

A\textsubscript{2b} — When resolving congestion, the CAISO Congestion Management System can adjust SC’s schedules within a tolerance of 0.03 MW, which is still considered a balanced portfolio and is not offset with a counter-balancing adjustment by the algorithm. For example, if there is a 50 MW load schedule, and a 50 MW generation schedule that gets adjusted to 49.97 MW, then the difference between the two is 0.03 MW; the net final flow into the zone. The net final flow into or out of a zone, depending on congestion conditions, is subject to congestion charges.

Q\textsubscript{3} (CT 254): Why didn’t I receive congestion revenues in CT 254 for my FTRs based on my percentage of entitlement on the path when there was a HA Congestion Price for a given hour?

A\textsubscript{3} — The HA congestion price on a path is not always an indication of revenues from NFU scheduled on the path. A price may exist as the result of a schedule being reduced in the HA from its DA schedule due to a derate. In that instance, when there is congestion in the HA and HA loading on the path is less than the DA loading, no CT
FAQs

254 will be generated for the path in question, but rather, CT 255 and/or 256 will be generated.

Q4 What is TO Debit and who is responsible for the payments associated with it?

A4 — In the event of a line derate between the DA and HA Market where ATC is reduced and congestion is present, TOs can incur a charge in the HA Congestion Market. This condition is referred to as the TO Debit and the payment responsibility is split between the TOs and the SCs, to prevent the TO from bearing the entirety of the charges. The TO Debit will be paid in part by the TO, via CT 255, and in part via CT 256 by SCs who received a payment in CT 253.

Q5 As an SC, why do I see a charge in CT 256 when no congestion occurred in the DA Market?

A5 – If DA congestion did not occur on a Branch Group, the price used in the CT 255 settlement calculation is $0, thus no charge will be given to the responsible TOs. The end result in this case will be that the SCs that had been scheduled to utilize the Branch Group in the DA will be charged via CT 256 to compensate for those who were settled via CT 253.

Q6 As an SC, why do I see a charge in CT 253 when no congestion occurred in the HA Market?

A6 – Having no CT 253 charges at a Branch Group does not mean there was no HA congestion at that Branch Group. If there is no change between an SC’s DA and HA schedules on a Branch Group then no CT 253 payments or charges will accrue for that SC, as the Billable Quantity component is based on incremental changes between the DA and HA. However, if there are other SCs that do change their schedules in the HA, either to the benefit of congestion or in the direction of it, then these SCs will be paid or charged respectively in CT 253. The CT 253 total is assessed to these SCs and in the event of a TO Debit condition, the CT 253 can be charged back to all SCs utilizing the congested path in the direction of congestion in CT 256.

Q7 Why were my schedules adjusted in the forward Markets when no congestion occurred where I had schedules?

A7 — If there is congestion anywhere on the grid, the CAISO Congestion Management (CONG) software will run its optimization algorithm, which resolves congestion and optimizes SC portfolios. An SC’s portfolio is considered optimized when there are no
beneficial opportunities to trade energy among its resources based on submitted adjustment bids; meaning the SC is using the most cost effective use of its resources (based on the adjustment bids submitted to the CAISO). There is an implicit expectation that SCs have already optimized their portfolios assuming no congestion. In the event an SC does not submit an optimized set of schedules within a zone, CONG will make adjustments to submitted adjustment bids to avoid adjusting resource schedules in the same zone in opposite directions.

For more information and examples, please see the CAISO white paper on this subject at http://www.caiso.com/docs/09003a6080/16/8f/09003a6080168f1d.pdf.

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**MLCC Payments and Allocations**

**Q** How does the CAISO determine the level at which a resource should be generating, as it appears that the \( P_{\text{min}} \) is incorporating "dispatches"?

**A** MRTU Phase 1B incorporates values for generating units relating to both \( P_{\text{min}} \) and Minimum Dispatchable Level (MDL), also known as the Dispatchable \( P_{\text{min}} \). The CAISO is using either the \( P_{\text{min}} \) or the MDL depending upon the forecasted operational needs of the CAISO and is not incorporating “dispatches” into the expected operating level upon which Minimum Load Cost Compensation is based. The decision to have a unit operate at its MDL is not considered a dispatch; rather it is the operating target for specified time period within the Waiver Denial Period. In Real Time, the CAISO may “dispatch” a unit above it’s \( P_{\text{min}} \) or MDL based on the bids submitted by the unit. These types of dispatches are settled as Instructed Energy.

Please refer to the values submitted as part of the Resource Data Template (RDT) prior to the implementation of Phase 1B, along with any subsequent updates to that data and Amendment 60 (which discusses how and why the CAISO proposed to use the MDL value) for more information.
FAQs

No Pay and Compliance

Q. Why am I being assessed No Pay charges for failure to deliver awarded Spinning Reserve energy when the generator did not receive a dispatch via ADS or phone?

A. The No Pay Charges are most likely the result of Undispatchable Capacity. Undispatchable Capacity No Pay charges can result from unit limitations submitted in the Supplemental Energy Bid template, or from the unit being off-line, which limit/prohibit the CAISO from dispatching energy from awarded Ancillary Services (A/S) capacity in real-time. Bid in unit limitations, such as start up time, ramp rate or unit outage, restrict the amount of energy available from the resource in 10 minutes. In addition, if a generator is offline the CAISO cannot dispatch it for SPIN, as Spinning Reserve requires a unit to be online (synched to the grid). Thus, if the resource sold more SPIN capacity than it can provide in 10 minutes, the CAISO will take back payment for the amount of capacity that was unavailable through this charge. This charge applies whether or not the CAISO has dispatched the unit. Thus, SCs must consider unit limitations when bidding in the A/S markets, and structure their Supplemental Energy Bids in a manner that will allow the CAISO to dispatch all awarded A/S capacity.

Q. What is SPIN_Instr_Qty?

A. SPIN Instr Qty is the amount of SPIN energy dispatched by ADS in MWs. This is used for Static System Resources (Interchanges) that submit A/S bids. These instructions can be declined through ADS. Therefore, the SPIN Instr Qty is the amount dispatched by the CAISO and accepted by the SC.

Q. What is SPIN_Ack_Qty?

A. SPIN Ack Qty is the amount of SPIN energy the SC for the Static System Resources indicates it will deliver. If a SC acknowledges an amount less than the instructed amount for the Static System Resource dispatched for SPIN energy then it is subject to No Pay for the portion declined.
FAQs

Q4 What is SPIN_IE_Qty?

A4 SPIN IE Qty is the amount of SPIN Instructed Imbalance Energy in MWhs that the CAISO dispatched and expected the SC to deliver by Static System Resources per Settlement Interval.

Q5 What is SPIN_Bill_Qty?

A5 SPIN Bill Qty is the No Pay billable quantity attributed to unavailable SPIN.

Q6 What are the criteria to calculate the tolerance factor for Undelivered Capacity?

A6 The No Pay Undelivered Capacity Tolerance Factor is always 10%. A SC is charged Undelivered Capacity when its resource is dispatched for A/S and under-delivers by more than 10%.

For example, when the unit has SPIN IIE = 50 MWh in an interval it is required to delivered at least \((1 - \text{Tolerance Factor}) \times \text{SPIN IIE}\), or 90% of 50 MWh in order to pass the No Pay Undelivered Capacity test. If the unit delivers at least 45 MWh or more, then it is not subject to No Pay Undelivered Capacity. If the unit delivers less than 45 MWh, for example 30 MWh, then the SC keeps the SPIN capacity payment for the amount it did deliver, 30 MWh, and will lose payment for the remainder of the SPIN capacity sold into the forward Markets for the Settlement Interval, 15 MWh.

Q7 The price for CT 4141 is the weighted average of the MCPs paid to a SC for Spinning Reserve Capacity in the DA and HA Markets. If SPIN is bid as “Self-Provided”, what is the price applied?

A7 The No Pay price for Self-Provided A/S is the MCP for that service, i.e. the unit is charged the weighted average of the SPIN MCPs as if it had participated in the Markets in which it scheduled the Self-Provision. For example, if the SPIN was scheduled in the DA Market as Self-Provision, then the No Pay price will be fully weighted on the DA SPIN MCP for that zone.
**Transmission Loss Obligation**

**Q:** Why is the derived price used in the Transmission Loss Obligation calculation excessively high?

**A:** Transmission Loss is the line loss that occurs when electricity is transmitted over power line. Transmission Loss is settled through CT 4450 and is settled at the Resource-Specific Price. A high or negative Resource-Specific price can result from a settlement interval in which both a net Inc and Dec dispatch instruction have been dispatched in each associated 5-minute dispatch interval.

**RESOURC**E**-SPECIFIC PRICE CALCULATION** = 10-Minute Weighted Average Price of two 5-minute Ex-Post Prices and two 5-minute Instructed Energy quantities *per Resource.*

**Example 1: Resource-Specific Price**

<table>
<thead>
<tr>
<th>Dispatch Interval</th>
<th>5-minute Price</th>
<th>IIE_Total</th>
<th>Resource-Specific Price (10-minute Settlement Price)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>$40</td>
<td>0.83</td>
<td>$46.68</td>
</tr>
<tr>
<td>2</td>
<td>$50</td>
<td>1.67</td>
<td></td>
</tr>
</tbody>
</table>

\[
\text{Resource-Specific Price} = \frac{((0.83\text{MWh} \times $40.00) + (1.67\text{MWh} \times $50.00))}{(0.83\text{MWh} + 1.67\text{MWh})}
\]

\[
\text{Resource-Specific Price} = \frac{$33.20 + $83.50}{2.5\text{MWh}} = \frac{$116.70}{2.5\text{MWh}}
\]

**Resource-Specific Price** = $46.68
Example 2: High Resource-Specific Price

<table>
<thead>
<tr>
<th>Dispatch Interval</th>
<th>5-minute Price</th>
<th>IIE_Total</th>
<th>Settlement Amount</th>
<th>Resource-Specific Price (10-minute Settlement Price)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>$0.001</td>
<td>-1.1</td>
<td>-0.0011</td>
<td>$1315.903</td>
</tr>
<tr>
<td>2</td>
<td>$46.173</td>
<td>1.14</td>
<td>52.63722</td>
<td></td>
</tr>
</tbody>
</table>

\[
\text{High Resource-Specific Price} = \frac{((-1.1 \text{MWh} \times $0.001) + (1.14 \text{MWh} \times $46.173))}{(-1.1 \text{MWh} + 1.14 \text{MWh})}
\]

\[
\text{High Resource-Specific Price} = \frac{($0.001 + $52.637)}{0.040 \text{MWh}} = \$526.38
\]

\[
\text{High Resource-Specific Price} = \$1315.903
\]

Example 3: Negative Resource-Specific Price

<table>
<thead>
<tr>
<th>Dispatch Interval</th>
<th>5-minute Price</th>
<th>IIE_Total</th>
<th>Settlement Amount</th>
<th>Resource-Specific Price (10-minute Settlement Price)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>$0.001</td>
<td>-1.1</td>
<td>-0.0011</td>
<td>$-800.314</td>
</tr>
<tr>
<td>2</td>
<td>$46.173</td>
<td>1.04</td>
<td>48.01992</td>
<td></td>
</tr>
</tbody>
</table>

\[
\text{Negative Resource-Specific Price} = \frac{((-1.1 \text{MWh} \times $0.001) + (1.04 \text{MWh} \times $46.173))}{(-1.1 \text{MWh} + 1.04 \text{MWh})}
\]

\[
\text{Negative Resource-Specific Price} = \frac{($0.001 + $48.020)}{-0.060 \text{MWh}} = \frac{$48.021}{-0.060 \text{MWh}}
\]

\[
\text{Negative Resource-Specific Price} = $-800.314
\]