California Independent System Operator Corporation

California ISO

Real-time load settlement price calculation causing revenue imbalances

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Department of Market Monitoring

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1 Executive Summary

The settlement calculation of the price demand pays is structurally different from the price generation supply is paid in the CAISO's real-time markets. Generation is paid incrementally: the difference between the day-ahead and 15-minute market schedule at the 15-minute price, and the difference between the 15-minute market schedule and the meter at the 5-minute price.

Most load (demand) pays a weighted average hourly price. Real-time non-dispatchable load is settled using a weighted average of the 15-minute and 5-minute market prices in each hour. In some hours, this hourly price is a weighted average of incremental load in the 15-minute and 5-minute markets. Under some real-time conditions, however, real-time load is settled on an *absolute value weighted price* calculated using the absolute value of the incremental load in the 15-minute and 5-minute markets.

The inconsistency between what generation is paid and what load pays creates real-time revenue imbalances. These imbalances are collected from load (measured demand) on a pro-rata basis as real-time imbalance offset costs. Using an *absolute value weighted average* price for load can cause the CAISO to collect less money for real-time load than is needed to cover real-time load costs paid to suppliers. This revenue shortfall, or negative revenue imbalance, is recovered through real-time revenue imbalance offset charges, which are allocated to total metered load plus exports. Recovering real-time energy costs through these revenue imbalance charges, rather than through the hourly price charged for real-time energy, shifts the allocation of these costs between load serving entities including exporters.

Settling load incrementally, as generation is settled, would change the distribution of real-time energy costs between exporters and load serving entities with metered load. The overall payment would not change. In this paper, DMM calculates real-time load cost shifts by comparing current load settlement values to a counterfactual case in which real-time load is settled incrementally. For CAISO in 2022:

- Settling real-time load with absolute value weighted prices created an estimated $143 million in real-time revenue imbalance offset costs for settlement of day-ahead to 5-minute market load.
- Settling 5-minute market to metered load with the current prices (either weighted average price or absolute value weighted price) relative to settling at the 5-minute market prices (which would be consistent with how supply is settled) created an estimated $59 million surplus in 2022.
- The total imbalance created by using the two calculated prices relative to settling load incrementally was $83 million.
- For the day-ahead to 5-minute load, DMM estimates a $24 million shift in net costs between market participants — including a shift of about $10 million in load costs to exporters.

The effects on cost transfers in the Western energy imbalance market (WEIM) cannot be estimated without data on WEIM area offset allocations. However, the total revenue imbalance for all WEIM areas due to this settlement feature was relatively low, about $10 million in 2022.

DMM recommends that the CAISO settle real-time load incrementally, and stop using both weighted prices for real-time load settlement, eliminating price inconsistencies. Specifically, DMM believes the CAISO should settle real-time load incrementally in each market directly using the market prices. Eliminating use of these weighted average prices will greatly reduce real-time energy revenue imbalances, provide clearer market transparency, and improve allocation of real-time energy costs based on cost-causation. This report describes an alternative methodology for settling load incrementally directly using the market prices which DMM believes would achieve these goals and be relatively easy to implement.

2 Real-time load settlement and revenue imbalances

The California ISO's real-time market dispatches supply resources in two financially binding real-time markets: the 15-minute market and 5-minute real-time dispatch. Dispatchable resources are settled incrementally from one market to the next.[1] The difference from day-ahead market schedules to 15-minute market schedules is settled at the 15-minute market prices. The difference between the 15-minute and 5-minute market schedules are settled at the 5-minute market prices. The difference between the 5-minute market schedules and metered amount is also settled at the 5-minute market price.

Real-time load is settled on the difference between hourly day-ahead load schedules and metered load using an hourly price calculated from the 15-minute and 5-minute real-time market prices. The CAISO uses two alternative calculations for this hourly load settlement price:

- **Weighted average price**. The first price is a weighted average price based on 15-minute and 5-minute real-time market prices, weighted by the differences in the load forecasts used by the market software in the 15-minute and 5-minute markets. The four 15-minute market prices for each hour are weighted based on the difference between hourly day-ahead load schedules and the 15-minute load forecast used by the real-time market software. The twelve 5-minute market prices for each hour are weighted based on the difference between 15-minute load forecast and 5-minute load forecasts used in the market. As shown later in this report, when multiplied by the difference between the day-ahead and 5-minute load, this weighted average price calculation would result in the same net settlement that would occur if load were settled incrementally in each 15-minute and 5-minute interval within the hour. However, this price is multiplied by the difference between day-ahead and metered load. As explained in Chapter 4, applying this price to the difference between day-ahead and metered load can be very problematic and lead to unworkable settlement results.

- **Absolute value weighted price.** When the hourly weighted average price described above is greater or lower than the range of 15-minute and 5-minute market prices during that hour, the CAISO uses a different method for calculating an hourly price.[2] The second approach weights the 15-minute and 5-minute prices by the *absolute value* of the differences in the load forecasts used in the 15-minute and 5-minute markets. Using absolute value of incremental load quantities does not result in the same net settlements that would result if load were settled incrementally. This discrepancy tends to cause the CAISO to collect less money from real-time load than is paid to generators in the real-time market, which creates real-time revenue imbalances.

[1] These dispatchable resources are comprised mostly of generation resources, but include a relatively small amount of dispatchable load comprised of pump loads and demand response, in addition to exports.

[2] That is, if the calculated weighted average price is greater than the maximum of the 15-minute and 5-minute prices, or less than the minimum of the 15-minute and 5-minute prices, then the ISO uses the absolute value weighted price. The absolute value weighted price is used whenever any price component (energy, congestion, losses, or GHG) is outside the range of the individual interval price components for the hour.

The CAISO uses real-time imbalance offset accounts to collect funds to pay for imbalance shortfalls or to allocate out imbalance surpluses. The net costs of these real-time imbalance offset accounts are allocated based on each participant's share of total system load plus exports – rather than the incremental real-time load of each participant. As a result, using the absolute value weighted price for real-time load settlements can lead to a shifting of real-time energy costs between market participants relative to how costs are allocated under an incremental pricing approach.

2.1 Real-time load settlement based on hourly weighted average prices

Table 2.1 shows a simplified hypothetical example illustrating how real-time load would be settled using a weighted average price, calculated based on the quantity of load used to clear the 15-minute and 5-minute markets. For simplicity, the 15-minute and 5-minute market quantities and prices are represented on an hourly level in this example.[3] This simplified example also assumes that actual load is settled based on the quantity of load clearing the 5-minute, rather than metered load values. Other sections of this report highlight the impact of these other details on the settlement process.

The first columns on the left side of Table 2.1 shows hypothetical data for real-time load quantities and prices for one hour. In this example:

- The incremental amount of load in the 15-minute market is 200 MW (1,200 MW – 1,000 MW).
- The incremental amount of load in the 5-minute market is -250 MW (950 MW – 1,200 MW).
- The total change in load from day-ahead to the 5-minute market is -50 MWh (950 MW - 1,000 MW).

Table 2.1. Calculation of weighted average real-time load settlement price

	Load		Market		Wtd price calc		Settlement	
Market	**Schedule**	**Change**	**Price**	**Cost**	**weights**	**Price**	**MWh**	**Payments**
Day-ahead	1,000							
15-minute	1,200	200	$80	$16,000	-4.0	-$320		
5-minute	950	-250	$20	-$5,000	5.0	$100		
Total		**-50**		**$11,000**	**1**	**-$220**	**-50**	**$11,000**

Using this example, we can calculate the settlements as if load were settled in each market using the market prices and load changes during this hour. As shown in the *Market Cost* column:

- 15-minute market payments would be $16,000 (200 MWh x $80/MWh).
- 5-minute market payments would be -$5,000 (-250 MWh x $20/MWh).

In this example, real-time load (in aggregate) would pay a net cost of $11,000 if settled based on the incremental quantities (or load change) in the 15-minute and 5-minute markets. Because the supply dispatched in the 15-minute and 5-minute markets will equal load, the total real-time payments to supply during this hour would be $11,000.

[3] In practice, there are four 15-minute interval prices and quantities, and twelve 5-minute prices and quantities for each hour. In addition, each of these interval prices include separate components for energy, congestion, and losses rather than a single price.

The four columns on the right side of Table 2.1 shows how load would be settled in this example using the hourly weighted average price based on the actual incremental quantities of load clearing in the 15-minute and 5-minute markets.

- The 15-minute market price is weighted by 200 divided by -50, which is -4.
- The 15-minute market component of the calculation is $80 times -4, which -$320.
- The 5-minute market prices is weighted by -250 divided by -50, which is 5.
- The 5-minute market component of the calculation is $20 times 5, which is $100.
- The overall real-time price is the sum of -$320 and $100, which is -$220.

Applying the real-time price to the change in load from day-ahead to the 5-minute market results in the ISO collecting $11,000 from real-time load (-$220/MWh times -50 MWh). Using this weighted average price, the ISO would collect $11,000 from load and pay $11,000 to supply, and revenue would be balanced.

2.2 How the use of absolute value weighted price creates revenue imbalances

Table 2.2 shows a simplified example of the real-time load average price calculation using the absolute value of the load changes as weights. The simplified market results used in this example are the same as Table 2.1 above. Therefore, to maintain revenue balance the CAISO would need to collect $11,000 to pay real-time supply.

In this example, since the weighted average price, calculated using the actual load difference quantities (-$220/MWh), is below the minimum price from the real-time markets ($20/MWh), the ISO settlement would not use this -$220/MWh price. Instead the CAISO would calculate a price using the absolute values of the load changes as weights. As shown in the right half of Table 2.2:

- The 15-minute market price is weighted by 200 over 450 (200 plus 250), which is 0.4.
- The 15-minute market component of the calculation is $80 times 0.4, which is $36.
- The 5-minute market price is weighted by 250 over 450, which is 0.6.
- The 5-minute market component of the calculation is $20 times 0.6, which is $11.
- The final absolute value weighted price is the sum of $36 and $11, which is $47.

In this example, the CAISO would *pay* real-time load $2,333 (-50 times $47) and pay supply $11,000. This results in a $13,333 revenue shortfall.

Table 2.2. Calculation of average real-time load settlement price with absolute weights

	Load		Market		Abs wtd price calc		Settlement	
Market	Schedule	Change	Price	Cost	weights	Price	MWh	Payments
Day-ahead	1,000							
15-minute	1,200	200	$80	$16,000	0.4	$36		
5-minute	950	-250	$20	-$5,000	0.6	$11		
Total		**-50**		**$11,000**	**1**	**$47**	**-50**	**-$2,333**

2.3 How the use of absolute value weighted load prices creates cost transfers

In the CAISO balancing area, real-time revenue imbalances are allocated to *measured demand* through imbalance offset accounts. These real-time imbalance offset accounts are allocated to individual scheduling coordinators based on their pro rata share of total measured demand. Measured demand includes total metered load plus exports.

To illustrate how the revenue imbalance caused by use of the absolute value weighted price can create cost transfers between participants, consider the example from Table 2.2 above. For this illustrative example, we can add another market participant with a 50 MWh export scheduled in the day-ahead market. In this example, the cost of serving real-time load is still $11,000, which would be charged to real-time load if the CAISO settled each market incrementally (as shown in Table 2.1). However, because the absolute value weighted price is used, not only is the $11,000 not collected, but load is instead paid $2,333 (as shown in Table 2.2). This $13,333 revenue shortfall is collected from total measured demand.

As shown in Table 2.3 below, market participants with incremental real-time load will pay for part, but not all, of this revenue shortfall. In this example, total measured demand is 1,000 MWh, or 950 MWh of load plus the 50 MWh export. Market participants with real-time load changes are allocated 95% of the imbalance (950 MWh divided by 1,000 MWh = .95). The export is allocated 5% of the imbalance shortfall (50 MW divided by 1,000 MW).

Individual load serving entities' share of total measured demand can be very different from their share of incremental real time energy (the difference between their day-ahead schedules and real-time demand). This means that settling real-time energy costs through real-time revenue imbalances can cause significant cost shifts between participants compared to an approach that allocates these costs based on each participant's incremental real-time demand through hourly real-time energy prices.

Table 2.3. Cost shift from using absolute value weighted load prices through imbalance allocation

Measured Demand	Demand	Allocation Factor	Total Shortfall	Shortfall Allocation	Real-Time Market Pmts	Net Payments
Real-time load participants	950	0.95	$13,333	$12,667	-$2,333	$10,333
Export	50	0.05	$13,333	$667	$0	$667
Total	**1,000**	**1.00**		**$13,333**		**$11,000**

In this example, real-time load participants are allocated $12,667 of the revenue shortfall. Including their $2,333 real-time load settlement, net payments equal $10,333. This is less than the $11,000 that real-time load cost. The remaining $667 of real-time load cost is paid by exports. This represents a $667 shift in real-time load costs caused by using the absolute value weighted price to settle real-time load.

3 Data analysis

Real-time load imbalance in the CAISO is settled as the incremental load from day-ahead market schedules to metered load — at a calculated weighted average hourly real-time price. Sometimes the CAISO uses incremental load as weights. At other times the CAISO uses the absolute value of the incremental loads as weights. As explained above, using the absolute value weighted price for the portion of load imbalance from day-ahead to 5-minute market schedules can create revenue shortfalls.

Analysis in Sections 3.1 through 3.5 summarizes the effect of using the absolute value weighted price to settle the portion of load imbalance from *day-ahead to 5-minute market schedules.* This analysis compares the total cost of day-ahead to 5-minute market load imbalance at the current hourly real-time price to the actual cost of that imbalance (i.e. what charges to load would be if real-time load were settled incrementally based on 15-minute and 5-minute market prices). For this analysis, DMM estimated the cost shifts from the current settlement relative to how load would have been settled incrementally in the 15-minute and 5-minute markets by calculating each participant's share of the real-time load forecasts based on each participant's share of total metered load.

Analysis in Section 3.6 instead summarizes the cost of applying the current hourly real-time price to the portion of load imbalance from 5-*minute market to metered load*, relative to cost of pricing this imbalance at the 5-minute market price.

3.1 Estimated revenue imbalance effects from using absolute value weighted prices

In 2022, the use of the absolute value weighted price created an estimated $143 million in CAISO real-time imbalances. Figure 3.1 shows these shortfalls broken out by month. During September, shortfalls created from the absolute value weighted price exceeded $75 million. Figure 3.2 shows the total imbalances split out by the contribution from each price component. The energy price component accounts for the majority of the deficits created by the absolute value weighted price.

Figure 3.1 Total shortfall created from settling real-time load with absolute value weighted price

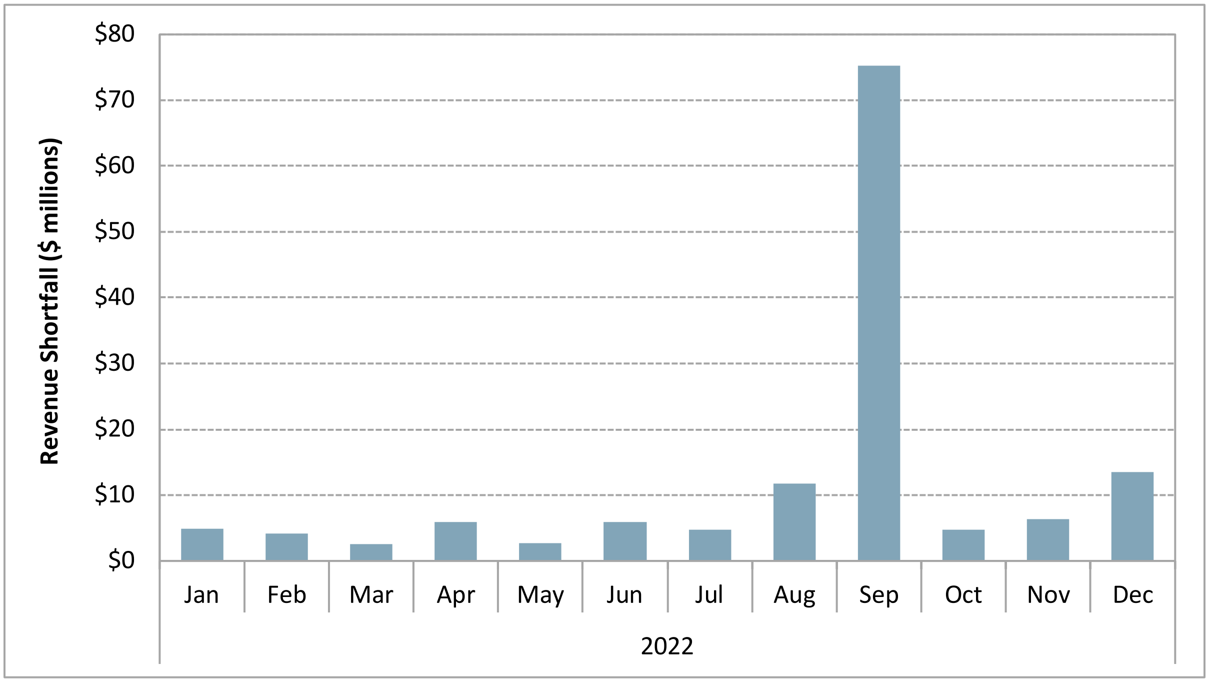
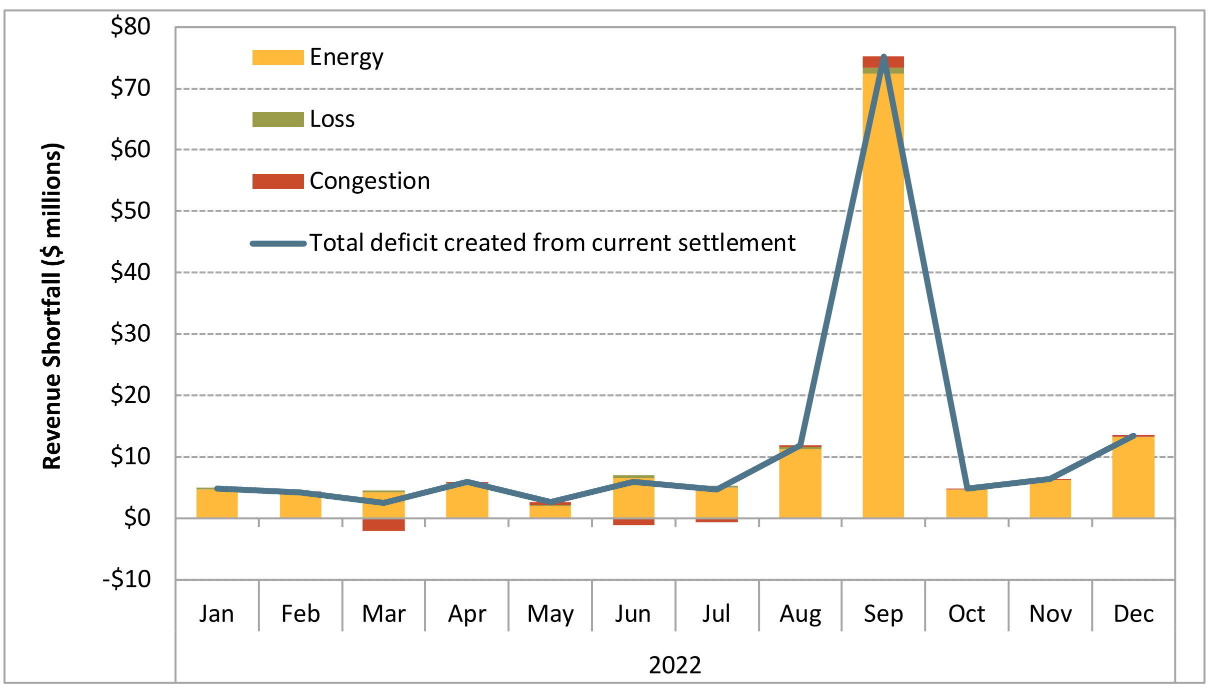


Figure 3.2 Total shortfall created from settling real-time load with absolute value weighted price by price component



3.2 Comparison of estimates to real-time energy imbalance offsets

During September, CAISO real-time energy imbalance offset costs reached almost $92 million – the highest monthly energy offset costs since the start of the nodal market in 2009. The absolute value weighted price caused a significant portion of the real-time energy offset costs.

Almost all energy offset costs in September occurred during the heatwave period between September 1 and September 8. Figure 3.3 compares the energy offset costs during this period with the estimated energy account shortfall created from the current settlement of real-time load using absolute-imbalance-weighted prices.

During September, the deficit created from absolute value weighted prices made up an estimated 79 percent of real-time energy imbalance offset costs. Figure 3.4 shows the same information by month for 2022. During the year, deficits created by settling the energy component of real-time load with the absolute value weighted price were $140 million, compared to almost $121 million in real-time energy imbalance offset costs.

Figure 3.3 CAISO real-time imbalance energy offset costs and energy account shortfall from settlement using absolute value weighted price (September 1 to September 8, 2022)

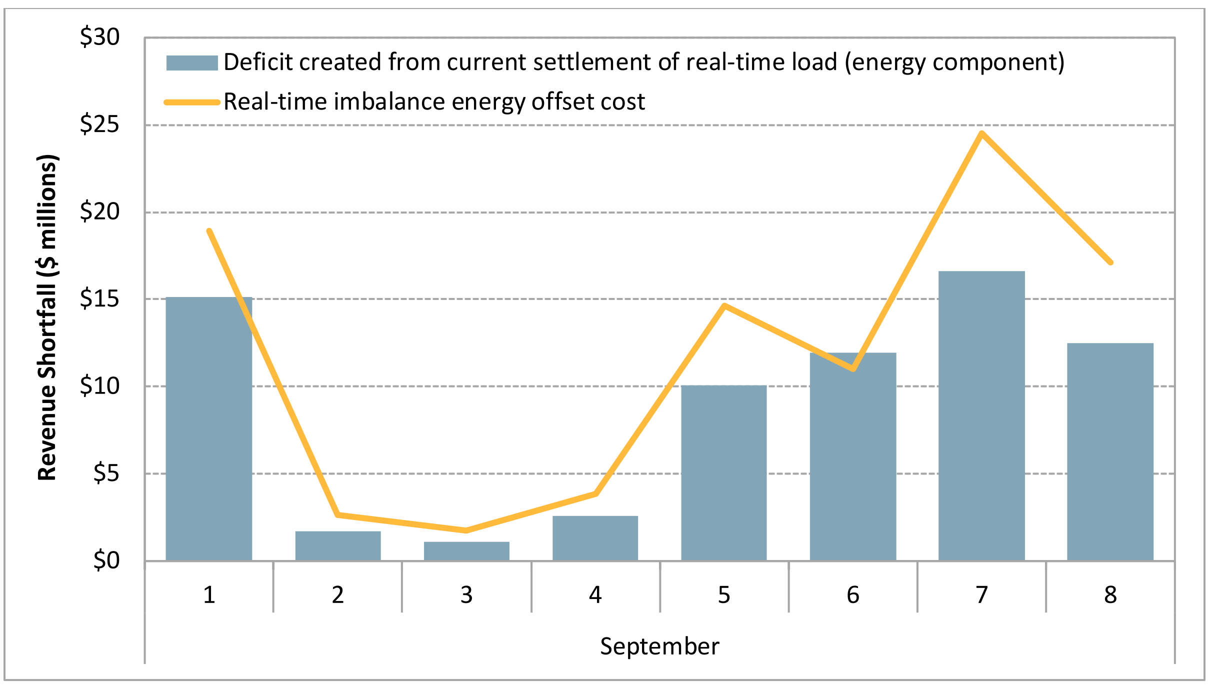
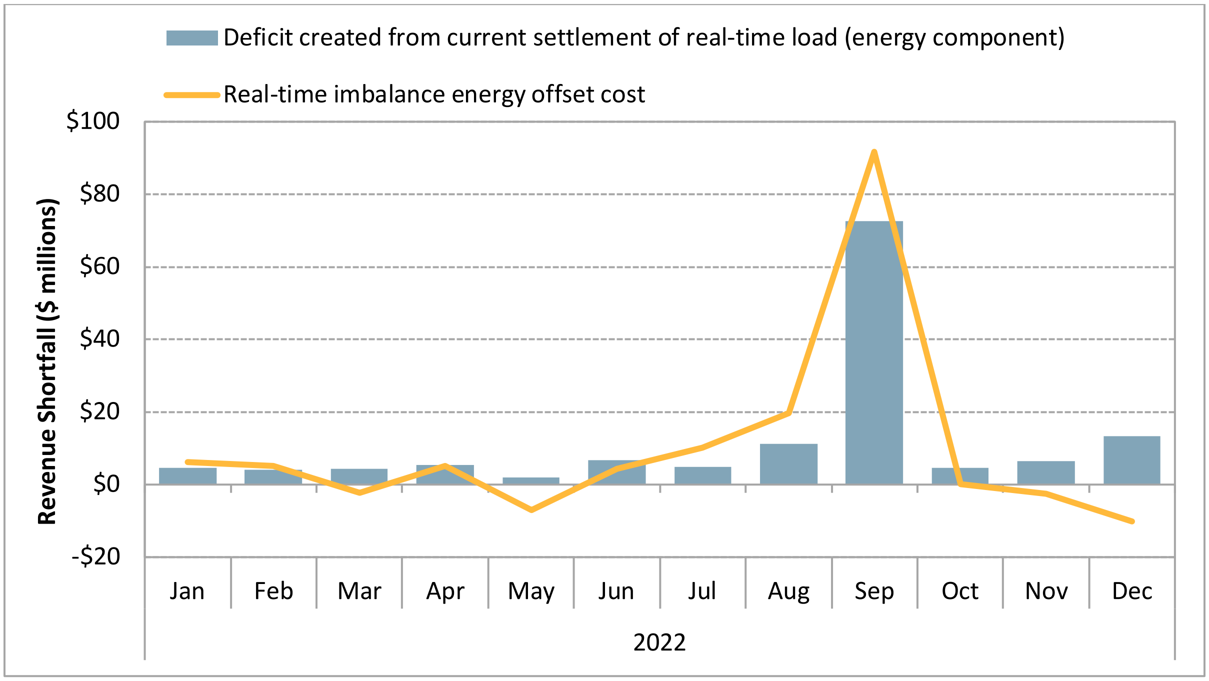


Figure 3.4 CAISO real-time imbalance energy offset costs and energy account shortfall from settlement using absolute value weighted price (2022)



3.3 Estimated net real-time cost shifts

In the CAISO balancing area, real-time revenue imbalances are allocated to measured demand through imbalance offset accounts. Measured demand is metered load plus exports. Because the costs of funding the real-time offset accounts are allocated differently than how costs would have been allocated if load were settled incrementally in the real-time markets, the current settlement can shift some of the real-time load costs from some market participants to other participants. This cost shift can occur not only between participants with CAISO load, but can also shift costs to exporters who may not have load.

The bars in Figure 3.5 show the estimated allocation of shortfalls created by the absolute value weighted price to metered load and exports. Total shortfalls were allocated based on each market participant's share of measured demand. The blue line shows the percent of deficits which were allocated to exports. During 2022, the absolute value weighted price shifted $9.9 million in costs to exports (or about 7 percent of the shortfall).

Figure 3.6 shows the estimated real-time load cost shifts by month during 2022. Here, each load market participant was assessed individually as net gain or net loss over the month and shown collectively in the yellow or blue bars.

- A *net gain* is when a participant paid less than their real-time load costs on net over the month—because some of their cost was transferred to others.
- A *net loss* is when a participant paid more than their real-time load costs on net over the month—because real-time load costs of other participants were transferred to them.

Netting over the entire year in 2022, estimated net CAISO load cost shifts between all market participants were $24 million, with $9.9 million of real-time load costs transferred to exports and the remaining $14.1 million transferred to other CAISO load.

Figure 3.5 Allocation of shortfall from settling real-time load with absolute value weighted price

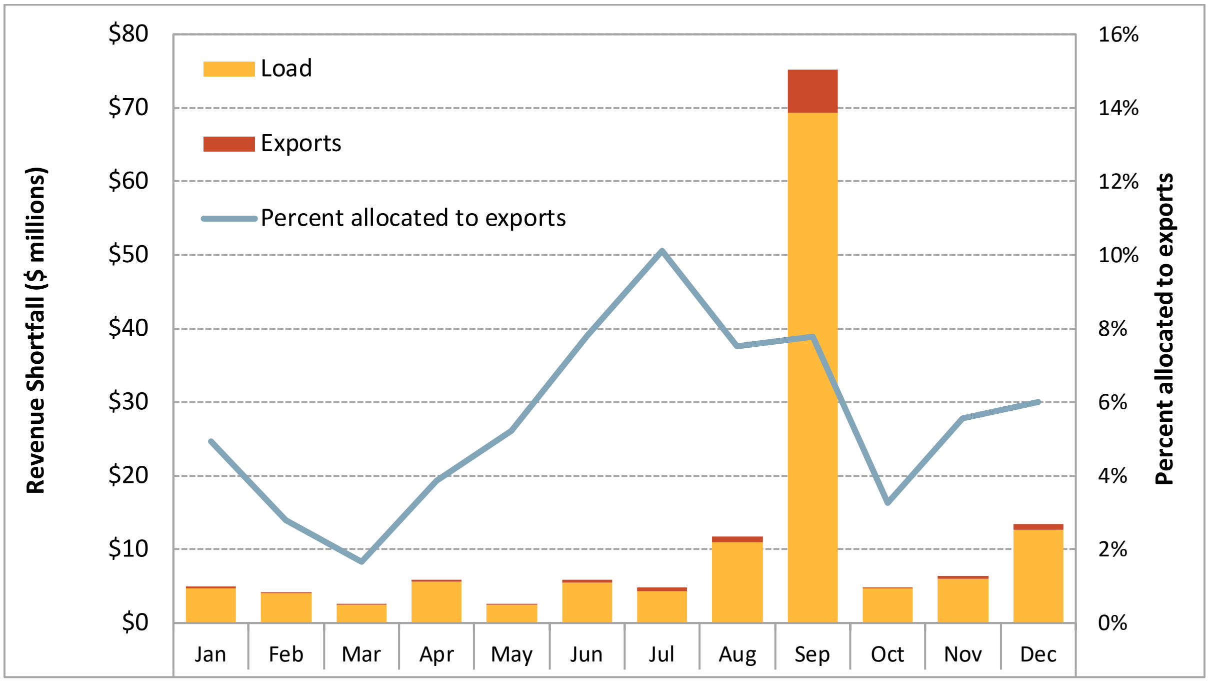
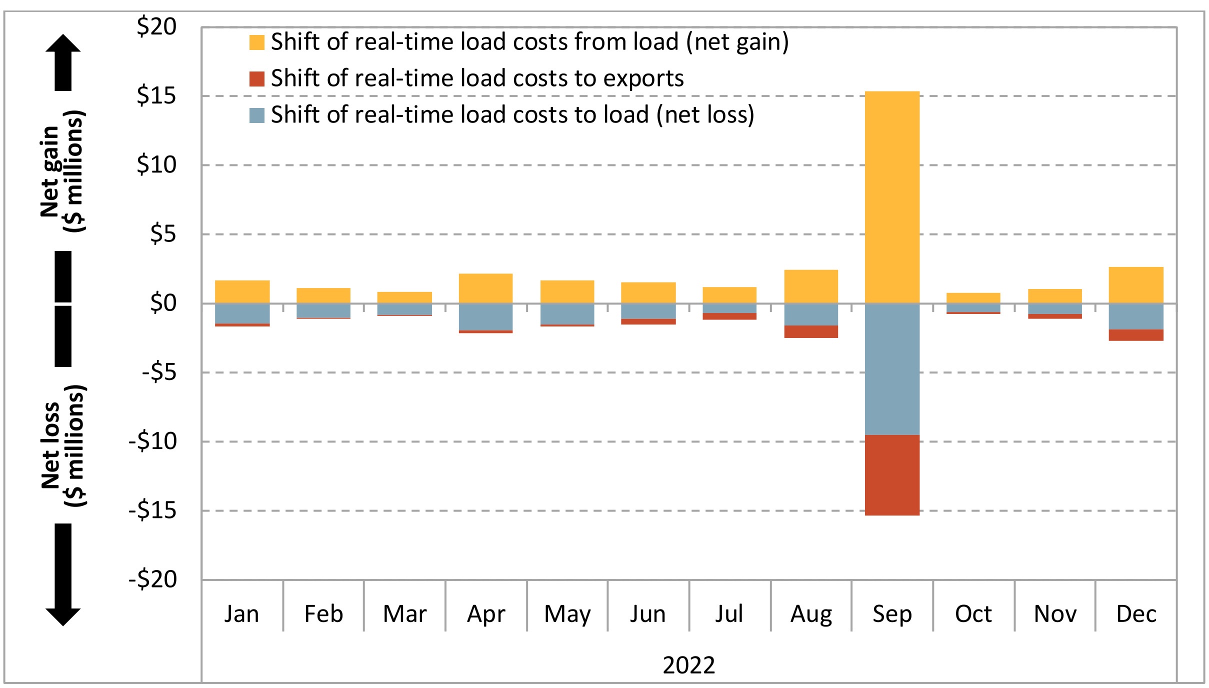


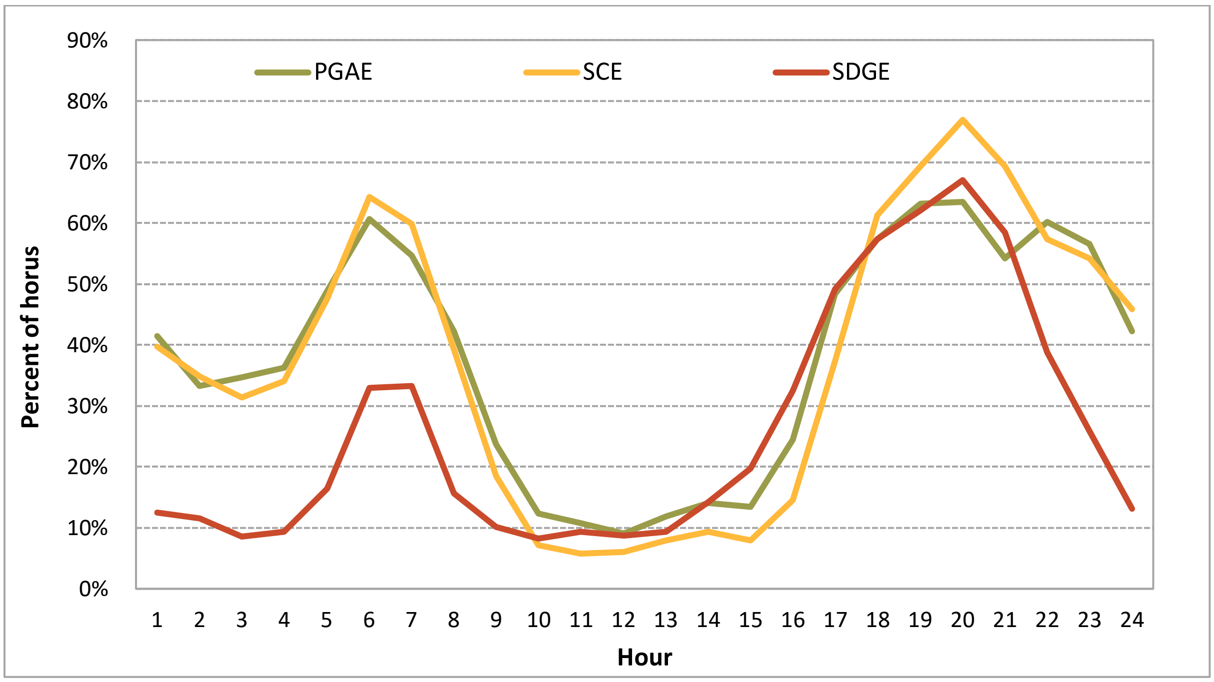
Figure 3.6 Estimated real-time load cost shift by demand type



3.4 Frequency of using absolute value weights in real-time load price calculations

The hourly average real-time price will be weighted by absolute imbalance from each interval if the weighted average price (or any price component) falls outside the range of all prices in the hour. Figure 3.7 shows the hourly frequency in which the average real-time price used to settle load imbalance was weighted by absolute imbalances across the hour — for each of the three major CAISO load aggregation points (LAPs). Between the peak net load hours of 17 and 21, absolute-imbalance-weighted prices were used in around 60 percent of hours across the major LAPs.

Figure 3.7 Percent of hourly with price weighted by absolute imbalance (January - December, 2022)

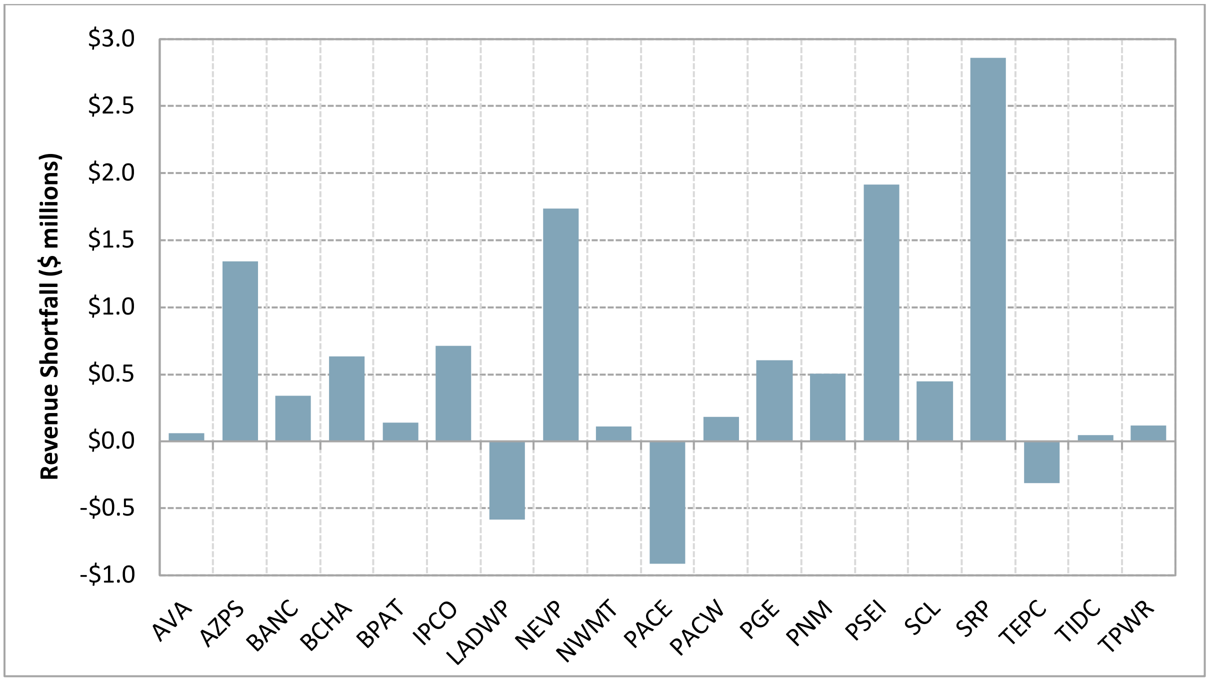


3.5 Estimated effects on WEIM balancing area revenue imbalances

The real-time load settlement price for each area in the Western Energy Imbalance Market (WEIM) is calculated in the same manner as that in the CAISO balancing area — i.e. based on the weighted average of the 15-minute and 5-minute market prices. While CAISO load is settled as day-ahead market to metered imbalance, load imbalance in the WEIM is settled as the incremental load from the hourly base schedules to metered load.

The estimated effect of using absolute-weighted prices on real-time revenue imbalances for WEIM areas was small relative to the CAISO area in 2022. Figure 3.8 summarizes the shortfall created for settling the portion of load imbalance from base to 5-minute market schedules at the absolute-weighted prices for each WEIM area during 2022. During 2022, the effect of using absolute-weighted prices on real-time revenue imbalance was less than $3 million for each WEIM area — or around $10 million across all WEIM areas.

Figure 3.8 Total shortfall created from current settlement of real-time load in WEIM (2022)



3.6 Estimated effects of applying hourly weighted prices on metered load imbalance

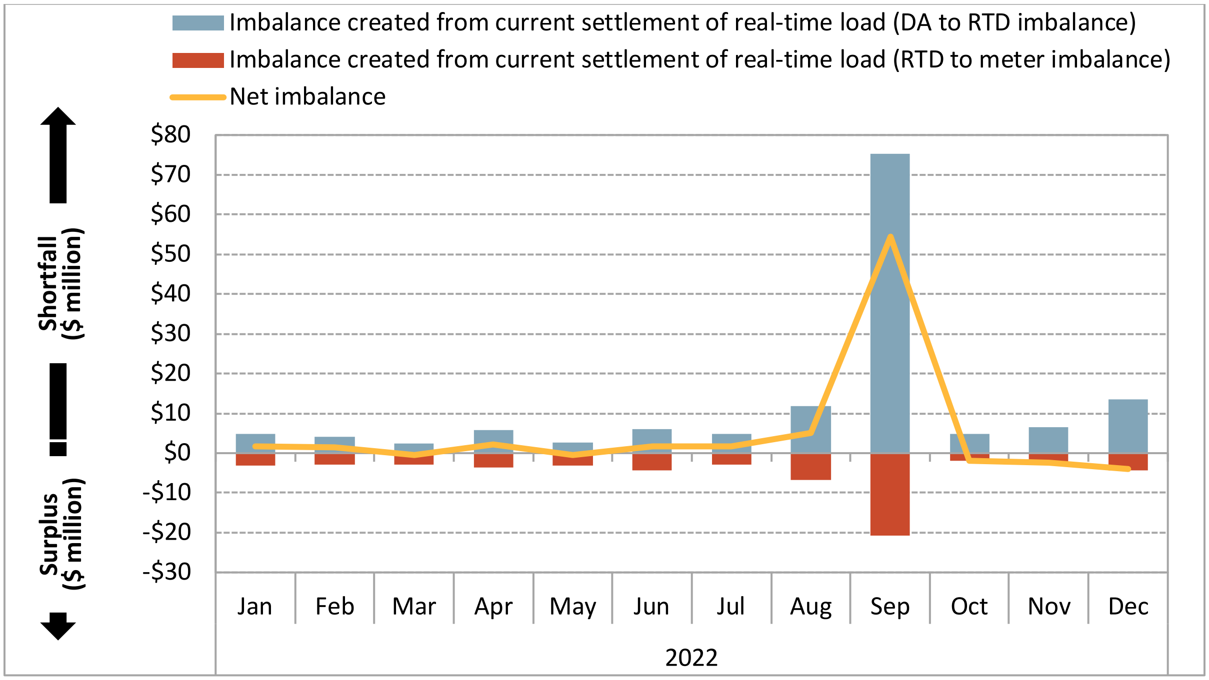
For dispatchable resources, imbalance between the 5-minute market schedules and metered quantities are settled at the 5-minute market price. However, for non-dispatchable load the (implied) difference between 5-minute market and metered load is settled at the calculated hourly real-time load settlement price. This section splits out the portion of load imbalance from 5-minute market schedules to metered values and compares the cost of that imbalance between using (1) the current hourly real-time price and (2) the 5-minute market price.

Figure 3.9 combines the effect of using the current price for settling day-ahead to 5-minute market imbalance (from Figure 3.1) with settling 5-minute market to metered imbalance. The day-ahead to 5-minute market effect measures the imbalance created with settling this portion using the absolute weighted hourly price, relative to settling this imbalance incrementally in the market. The 5-minute market to metered effect measures the imbalance created with settling this portion using the current hourly real-time price, relative to setting this imbalance at the 5-minute market price.

As shown in Figure 3.9, total shortfalls created from settling day-ahead to 5-minute market imbalance using the hourly real-time price were in part offset by the effect of settling 5-minute market to metered imbalance at the same price. Settling the metered imbalance using the hourly real-time price created $59 million in surplus, relative to the cost of that imbalance with the 5-minute market price instead applied. After netting both effects, the current settlement created $83 million in CAISO real-time revenue shortfall.

In a later section, DMM recommends that load be settled incrementally in each market directly using the market price. The results in Figure 3.9 are consistent with the imbalances that would be prevented with this recommendation.

Figure 3.9 Total imbalances created from current settlement of real-time load



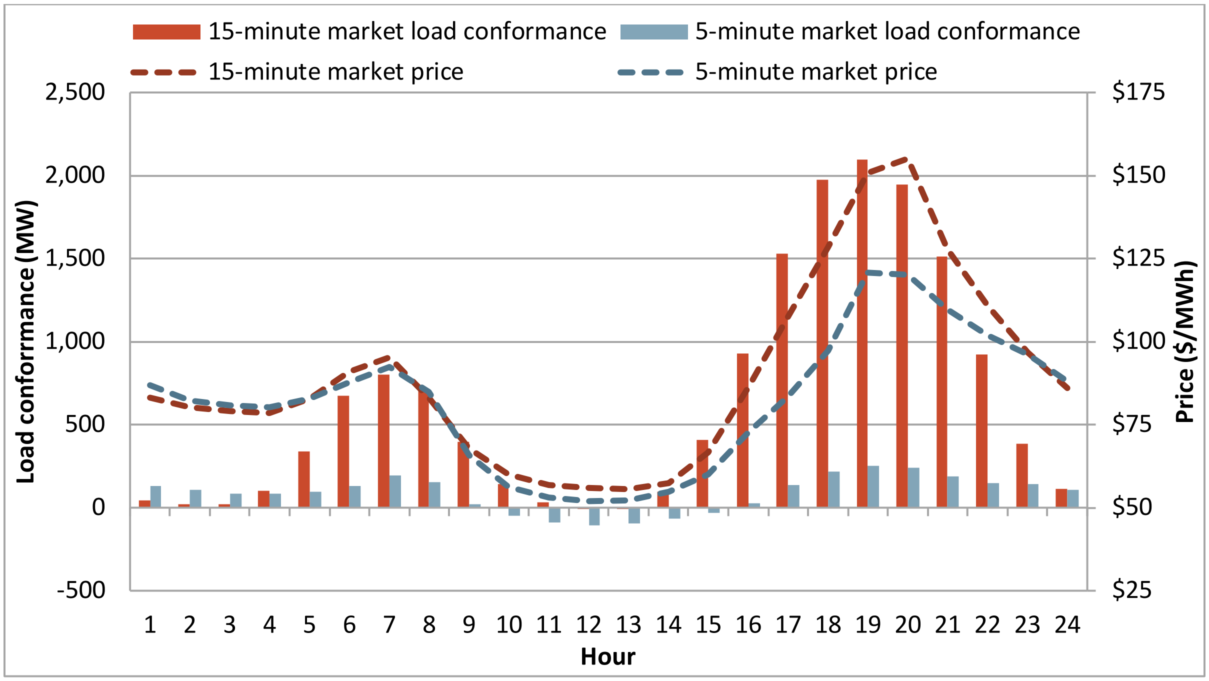
3.7 Effect of load bias adjustments

Operators can modify the load forecasts used in the market through load bias adjustments. In CAISO, these adjustments are routinely used in the hour-ahead and 15-minute scheduling processes to increase capacity to address uncertainty that can materialize around net load ramping periods. Here, the real-time market optimization solves for load plus any bias, clearing additional hourly imports, reducing hourly exports, and committing more internal generation than would have occurred otherwise.

The bars in Figure 3.10 show average hourly load adjustments in the 15-minute and 5-minute markets during 2022. These are also compared against load-weighted average energy prices across the three largest aggregation points in the California ISO. Significant load bias adjustments entered by CAISO operators in the 15-minute market during the peak hours often increased load well above that realized in the 5-mintue market. This contributed to higher prices in the 15-minute market relative to the 5-minute market — especially when supply conditions were tight.

Significant price differentials between the 15-minute and 5-minute markets driven by operator load bias can exacerbate revenue shortfalls when the real-time price used to settle load imbalance is weighted by absolute imbalances. Here, the bias introduces a cost that needs to be recovered as bias energy is bought high in the 15-minute market and sold low in the 5-minute market. This can be considered as the cost associated with procuring additional capacity to meet reliability needs in the 15-minute market horizon. Then, when the hourly real-time price is weighted by *absolute imbalance*, the costs associated with the bias can be greater than real-time payments from load — therefore resulting in revenue shortfalls that are recovered through real-time imbalance offset charges.

Figure 3.10 Average hourly load bias and energy prices (2022)



Load bias adjustments can also contribute to conditions that trigger absolute-imbalance-weighted hourly prices for real-time load settlement. For example, assume that total load imbalance from day-ahead through the 5-minute market happened to be *negative*, at -100 MWh. Also assume that significant load bias in the 15-minute market resulted in a *positive* real-time market cost at $200,000 (i.e. positive load imbalance and prices in the 15-minute market exceeded negative load imbalance and prices in the 5-minute market). In order to balance revenue, the price to charge load for the -100 MWh imbalance to get the real-time load cost of $200,000 (which includes the costs of load conformance) would be -$2,000/MWh. This is mathematically equal to the hourly real-time price that would be calculated without weighting by absolute imbalance. However, since the price is negative and falls below the minimum LMP for the hour, absolute weighting instead results in a positive price that when multiplied by the total imbalance (-100 MWh) results in load getting paid rather than charged. This revenue shortfall is then allocated to total metered load and exports through imbalance offset charges.

Even when load bias is zero, the same issues surrounding revenue shortfalls and inappropriate costs shifts between market participants can occur. Here, the conditions can still exist without bias that trigger absolute-weighted pricing and lead to insufficient collection of cost from load for real-time imbalance — which ultimately shifts costs through imbalance offset charges.

4 Issues with settling load using a single weighted price

Day-ahead to meter load imbalance is settled using a weighted average of the 15-minute and 5-minute market prices in each hour. In some hours, this hourly price is a weighted average from incremental load in the 15-minute and 5-minute markets. Under other conditions, real-time load is instead settled on an average price weighted using the *absolute value* of the incremental load in the 15-minute and 5-minute markets. As shown in the previous section, the absolute value version of the hourly weighted price can result in significant shortfalls that must be instead settled through imbalance offset costs.

However, issues also arise if the hourly price weighted only from the simple imbalance of incremental load in the 15-minute and 5-minute markets was used in *all* hours — effectively replacing the absolute value weighted prices. This section summarizes issues both with this approach as well as a modified approach. The modified approach addresses some of the shortcomings of the original approach by factoring in metered imbalance in the hourly weighted price to maintain revenue balance in total, but retains other issues with the allocation of costs at a participant level.

4.1 Why *current* incremental load weighted prices cannot replace absolute value weighted prices

Even though settling load with absolute value weighted average prices is inconsistent with real-time market results, which can result in significant revenue imbalances, the CAISO cannot simply use only the incremental load weighted price. This is because the current incremental load weighted price is only mathematically consistent for settling the day-ahead to 5-minute market load change.

In practice, real-time load prices are used to settle the total difference between day-ahead scheduled load and metered load. Applying the incremental load weighted price (without absolutes) to the total difference between day-ahead scheduled load and metered load can also lead to nonsensical settlement results. As described below, this could result when the incremental load weighted price is combined with small denominators (i.e. net incremental load quantities) in the settlement price calculation.

To illustrate, consider a load aggregation point where the total cost of real-time load in an hour, across both the 15-minute and 5-minute markets, was $200,000. But the overall change in load between day-ahead schedules and the 5-minute forecast was 0.0001 MWh. The hourly incremental load weighted price would equal $2 billion per MWh. In this scenario, if metered load were 5 MWh below day-ahead schedules this would create a $10 billion revenue shortfall.

The incremental load weighted price maintains total revenue balance from day-ahead to 5-minute market schedules but will create imbalance when applied to the difference between day-ahead and metered schedules. This price can be modified to maintain total revenue balance from day-ahead schedules through metered schedules, but this would not address a separate issue associated with cost allocation at the *load participant level*. Here, the use of incremental load weighted prices can result in inappropriate cost allocation for individual load participants even if total revenue balance is maintained. This is discussed in the following section.

4.2 Why *modified* incremental load weighted prices cannot replace absolute value weighted prices

The current weighted average price uses the load changes between day-ahead, 15-minute, and 5-minute markets as the weights. As discussed above, this weighted average price can create extreme settlement outcomes and revenue imbalances under certain conditions. Such extreme imbalances can be avoided without resorting to the absolute value weighted price by modifying the weights to include the difference between the 5-minute market and *metered load.* Including metered load in the weights will address the issue discussed in the previous section by ensuring that revenue from day-ahead to metered schedules will be balanced — *on total.* However, for individual market participants, this approach creates prices that arbitrarily allocate real-time costs to those with a greater share of imbalance.

The examples below highlight how weighted average prices do not allocate costs under a consistent principle.[4] For simplicity, total metered load in the examples equal 5-minute market load. This ensures revenue balance while still highlighting how weighted average price settlement can create arbitrary cost shifts for individual market participants. Each example has two load serving entities, Load A and Load B. Each load has 90 MW of metered load, or 180 MW in total. The 5-minute market forecast equals the total metered load of 180 MW. The 15-minute market forecast is 10 MW higher at 190 MW. The 15-minute market price is $35/MWh and the 5-minute market price is $25/MWh.

Assume the 15-minute forecast is higher than the 5-minute forecast because the CAISO entered 10 MW of load bias in the 15-minute market but not the 5-minute market. These 10 MW are bought at $35/MWh and sold at $25/MWh — creating a $100 cost from the bias. The examples below look at how this bias cost is allocated under the single weighted average prices as only the day-ahead scheduled load changes.

In the first example (Table 4.1), Load A scheduled *less* load in the day-ahead market than its real-time metered load. Load A schedules 80 MW of load in the day-ahead market and metered 90 MW of load. Therefore, Load A will have 10 MW settled at the weighted average price. Load B has 90 MW of day-ahead scheduled and metered load and no real-time load settlement. With these day-ahead scheduled loads, the weighted average price is $45/MWh. Load A’s total settlement is $450 (10 MW multiplied by $45/MWh).

Load A’s real-time energy market settlement can be broken out from the total settlement. The 15-minute market price, $35/MWh, times the 10 MW incremental energy is the market settlement for energy, $350. The remaining $100, $450 minus $350, is the bias cost. The entire bias cost is allocated to Load A. In this example, the bias costs are allocated to Load A because they scheduled less load in day-ahead than their real-time meter.

[4] Again, the 15-minute and 5-minute market quantities and prices are represented on an hourly level for simplicity. In practice, there are four 15-minute interval prices and quantities, and twelve 5-minute prices and quantities for each hour.

Table 4.1 Example 1 – Load A schedules 80 MW in day-ahead market, 10 MW *below* metered (weighted average price settlement)

	Day-ahead	15-min	5-min	Meter	Meter minus day-ahead	Total settlement	Energy settlement	Bias cost allocation
Forecast		190	180					
Load A	80			90	10	$450	$350	$100
Load B	90			90	0	$0	$0	$0
Total	**170**	**190**	**180**	**180**	**10**	**$450**		
Price		$35	$25		***Wtd avg price***	$45		

Table 4.2 instead shows if Load A scheduled *more* load in the day-ahead market than its real-time metered load. Load B again has no real-time load settlement because its day-ahead schedule equals its meter. Therefore Load A, having the only non-zero real-time incremental load megawatts (-10 MW), would still have to pay for the bias cost ($100). In some cases, the bias costs would be paid by incremental real-time loads. In other cases, the same bias costs would be paid by decremental real-time loads.

Table 4.2 Example 2 – Load A schedules 100 MW in day-ahead market, 10 MW *above* metered (weighted average price settlement)

	Day-ahead	15-min	5-min	Meter	Meter minus day-ahead	Total settlement	Energy settlement	Bias cost allocation
Forecast		190	180					
Load A	100			90	-10	-$250	-$350	$100
Load B	90			90	0	$0	$0	$0
Total	**190**	**190**	**180**	**180**	**-10**	**-$250**		
Price		$35	$25		***Wtd avg price***	$25		

Going back to example 1 when Load A scheduled less load in the day-ahead market, Table 4.3 shows how the bias cost allocation changes as Load B's day-ahead schedule changes. Load A again schedules 80 MW of load in the day-ahead market and metered 90 MW of load. This time however, Load B schedules 91 MW of load in the day-ahead market; one megawatt more than its metered load. Now Load A is allocated $111 more than its incremental energy cost. This is $11 more than the $100 bias cost. The bias cost allocated to Load B is -$11 (i.e. Load B is paid $11). This $11 is a transfer of money from Load A to Load B.

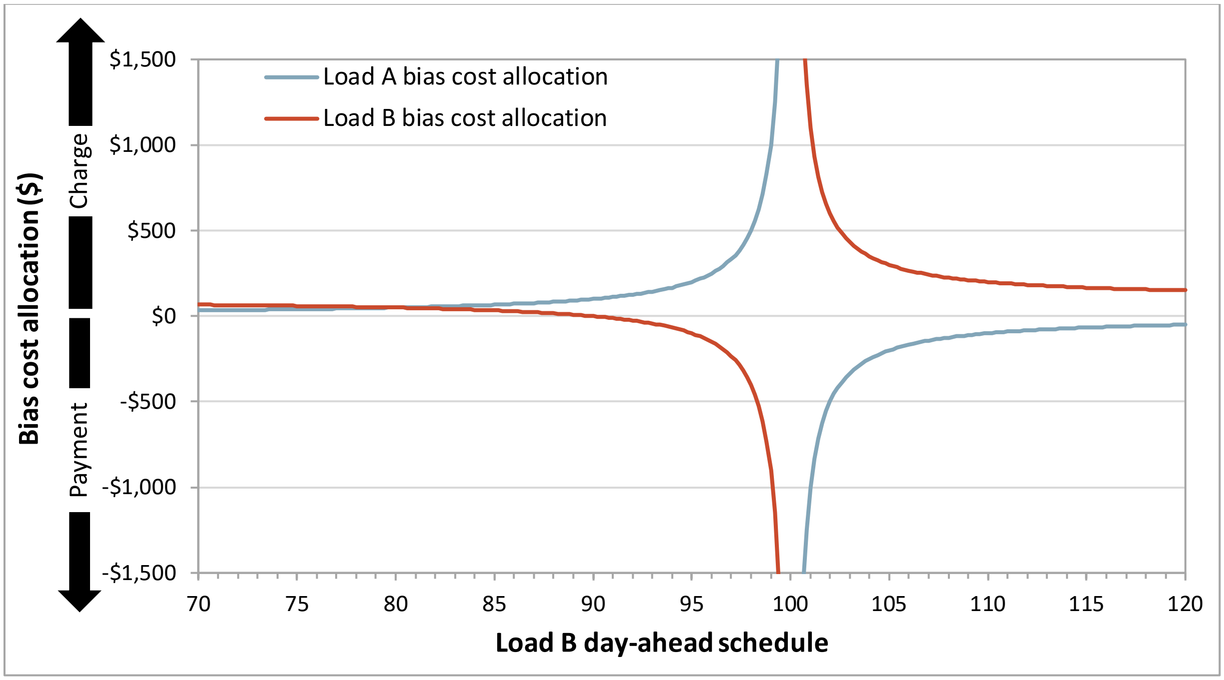
Table 4.3 Example 3 – Load B schedules 91 MW in day-ahead market (weighted average price settlement)

	Day-ahead	15-min	5-min	Meter	Meter minus day-ahead	Total settlement	Energy settlement	Bias cost allocation
Forecast		190	180					
Load A	80			90	10	$461	$350	$111
Load B	91			90	-1	-$46	-$35	-$11
Total	**171**	**190**	**180**	**180**	**9**	**$415**		
Price		$35	$25		***Wtd avg price***	$46.1		

The way in which the weighted average price allocates the costs of load bias or other load forecast error varies greatly. Figure 4.1 shows the allocation of the $100 cost of bias (including any cost transfers between Load A and Load B) for various day-ahead schedules from Load B. All the other values from the previous example are held constant — Load A schedules 10 MW less in the day-ahead market than metered load at 80 MW and the cost of the load bias is always $100. In all of the outcomes, the weighted average price maintains total revenue balance. However, at a load participant level, these costs are allocated arbitrarily to those with a greater share of day-ahead to metered imbalance in the same direction. For example, if Load A day-ahead to metered imbalance was +10 MW and Load B day-ahead to metered imbalance was -5 MW, then Load A would have a larger share of the total imbalance in the same direction and would therefore pay for the load bias (including cost transfers). However, if Load B day-ahead to metered imbalance was instead -15 MW, then Load B would have a larger share of the total imbalance in the same direction and would therefore pay for the load bias (including cost transfers). This is shown in Figure 4.1.

The hourly weighted real-time price can be modified to account for metered imbalance. This will maintain revenue balance in total, but will still allocate real-time costs arbitrarily at a load participant level to those with a greater share of day-ahead to metered imbalance. This allocation is disconnected from any cost causation principles associated with the underlying real-time costs.

Figure 4.1 Load bias cost allocation as Load B day-ahead schedule changes



5 Incremental real-time load settlement

As described in the previous sections of this report, the CAISO's current real-time load settlement rules sometimes uses an absolute value weighted price which is inconsistent with the real-time market results. This creates unnecessary revenue imbalances and shifts costs between market participants. DMM recommends that the CAISO stop using any single weighted average price, and adopt an approach that makes real-time load settlements consistent with real-time market dispatch and prices. This section describes such an alternative settlement methodology.

Simply eliminating the use of the absolute value weighted price (and relying instead on the load weighted average price) will not be sufficient to minimize revenue imbalances and cost shifts resulting from this issue. This load weighted average price, even when calculated with incremental load weights, only replicates the total market settlement for the difference between day-ahead scheduled load and the five-minute real-time dispatch. Further, modifying the load weighted average price to account for metered load and maintain total revenue balance will still have issues with how costs are allocated for individual market participants.

Using any single price to settle load imbalance can create adverse outcomes or result in arbitrary cost shifts between market participants. A single weighted price can be calculated to ensure that real-time revenue is balanced *on total*, but these prices can create cost shifts between individual market participants that are inconsistent with the underlying causation of those costs.

Another way to settle load, without creating unnecessary revenue imbalances, would be to settle each market incrementally relative to the previous market, as is done with supply schedules. This approach can be summarized as follows:

- Settle the difference between day-ahead load schedule and 15-minute load forecast at the 15-minute price;
- Settle the difference between the 15-minute and 5-minute load forecast at the 5-minute price; and
- Settle the difference between 5-minute load forecast and hourly metered quantity at the 5-minute dispatch price.

Because the quantity of non-participating load that is used to clear the 15-minute and 5-minute markets is based on forecasts, 15-minute and 5-minute load quantities for individual market participants cannot be used in this process. Instead, with this approach the CAISO would need to portion out the 15-minute and 5-minute forecasts to create 15-minute and 5-minute load schedules by participant to settle. DMM suggests that each participant's share of the 15-minute and 5-minute load forecasts be calculated based directly on each participant's share of total metered load.

These forecast shares can then be settled incrementally using the market prices.[5] This incremental settlement would be revenue balanced. Here, each market participant's day-ahead to real-time incremental load would be settled at the real-time market price and any costs associated with load bias or forecast error would be allocated pro-rata based on metered load. DMM believes this could be a reasonable and relatively simple approach to settle load incrementally by market.[6]

Table 5.1 through Table 5.3 show the same example from the previous section, except settled incrementally. As the tables show, Load A and Load B each have their incremental load settled at the real-time market price, and the $100 bias cost is consistently allocated pro-rata based on metered load. While the hourly weighted average price discussed in the previous section allocates real-time load costs to participants with a greater share of total day-ahead to metered load imbalance, the incremental approach allocates real-time load costs to those with a greater share of total metered load. DMM believes that this allocation of real-time load costs, including any cost of load bias or load forecast error, is more consistent with the drivers of those costs.

Table 5.1 Example 1 – Load A schedules 80 MW in day-ahead market, 10 MW *below* metered (incremental real-time settlement)

	Day-ahead	Forecast share		Incremental		Settlement		Total settlement	Energy settlement	Bias cost allocation
		15-min	5-min	15-min	5-min	15-min	5-min			
Load A	80	95	90	15	-5	$525	-$125	$400	$350	$50
Load B	90	95	90	5	-5	$175	-$125	$50	$0	$50
Total	**170**	**190**	**180**	**20**	**-10**	**$700**	**-$250**	**$450**		
Price		$35	$25							

5 The 15-minute forecast share minus the entity's day-ahead schedule settled at the 15-minute market price. The 5-minute forecast share minus the 15-minute forecast share at the 5-minute market price.

6 Estimated distribution factors would need to be used until the CAISO receives the meter data.

Table 5.2 Example 2 – Load A schedules 100 MW in day-ahead market, 10 MW *above* metered (incremental real-time settlement)

	Day-ahead	Forecast share		Incremental		Settlement		Total settlement	Energy settlement	Bias cost allocation
		15-min	5-min	15-min	5-min	15-min	5-min			
Load A	100	95	90	-5	-5	-$175	-$125	-$300	-$350	$50
Load B	90	95	90	5	-5	$175	-$125	$50	$0	$50
Total	**190**	**190**	**180**	**0**	**-10**	**$0**	**-$250**	**-$250**		
Price		$35	$25							

Table 5.3 Example 3 – Load B schedules 91 MW in day-ahead market (incremental real-time settlement)

	Day-ahead	Forecast share		Incremental		Settlement		Total settlement	Energy settlement	Bias cost allocation
		15-min	5-min	15-min	5-min	15-min	5-min			
Load A	80	95	90	15	-5	$525	-$125	$400	$350	$50
Load B	91	95	90	4	-5	$140	-$125	$15	-$35	$50
Total	**171**	**190**	**180**	**19**	**-10**	**$665**	**-$250**	**$415**		
Price		$35	$25							

As discussed in Section 3.7, significant load bias entered by CAISO operators in the 15-minute market introduces a cost as bias energy is bought in the 15-minute market at a higher price and sold in the 5-minute market at a lower price. This cost is then paid for by load (or exports as well when the costs are recovered through imbalance energy offset charges under the current settlement).

Some might argue that not all these bias costs should be allocated to load. The CAISO operators will sometimes bias load in the 15-minute market, not because they think the forecast is off, but to procure additional reserves and flexibility. The costs of the bias should be allocated to the drivers of this need for reserves, such as net load uncertainty.

The real-time load settlement should not be used to try and allocate the costs of this type of biasing to non-load drivers. Trying to determine which load bias was done for what reasons would be difficult. Altering the load settlement to allocate costs to non-load schedules would be more difficult still and likely lead to unintended consequences. The best way to allocate these costs would be to create a reserve product to replace the load bias and allocate the costs of the product to the drivers of that product's procurement.

Settling load incrementally by market would be consistent with the real-time market results. Because incremental settlements would use the market prices directly, these settlements would also have more clearly understandable prices. Directly using market prices would also be less prone to unintended consequences than the current use of single weighted averages price applied to the difference between meter and day-ahead load.

APPENDIX: Detailed real-time load price calculation example

Table A.1 highlights an example for the Pacific Gas and Electric load aggregation point (LAP) for hour-ending 19 on August 31, 2022. The example shows the calculation of the hourly weighted price used to settle load imbalance and the shortfall that was created by weighting prices using absolute imbalance in each interval. On the left end, the table shows the price and imbalance in each 15-minute and 5-minute market interval.[7] During this hour, total imbalance from day-ahead to 5-minute market schedules was -136.15 MWh.

The initial hourly price is calculated as the average price across the hour, with the price in each interval weighted by the corresponding imbalance. This results in the following hourly weighted price:

$$\text{-\$3,230.20/MWh} = \left[\left(\$286.85 \times \frac{256.15}{-136.15}\right) + \left(\$750.24 \times \frac{278.67}{-136.15}\right) + \cdots\right]$$

Multiplying this price by the total imbalance over the hour would equal exactly the cost of settling load incrementally in the real-time market:

$$\text{-136.15 MWh} \times \text{-\$3,230.20/MWh} = \$439{,}794$$

However, since the -$3,230.20/MWh price falls outside of the minimum and maximum range of prices in the hour, the average hourly price is instead calculated using *absolute imbalance* to weight the price in each interval. This results in the hourly real-time price of $435.22/MWh.

The $435/MWh price is disconnected from the results of the real-time market. Using this price to charge load for imbalance in the real-time market results in a total cost of -$59,256. As a result, load is *paid* $59K instead of charged $439K, therefore creating a shortfall of just under $500K for this one hour and LAP.

[7] 15-minute market imbalance is measured as the difference between 15-minute and day-ahead market schedules. 5-minute market imbalance is the difference between 5-minute and 15-minute market schedules.

Table A.1 Example hour, calculation of hourly weighted price (Pacific Gas and Electric LAP, August 31, 2022, hour 19)

Market	Interval	Price	DA LAP schedule (MW)	FMM LAP schedule (MW)	Imbalance (MWh)	Imbalance (percent of total)	*Absolute imbalance (MWh)*	*Abs. imbalance (percent of total)*	Weighted price (imbalance)	Weighted price (abs. imbalance)
15-minute market	1	$286.85	16,489	17,513	256.15	-188%	256.15	11%	-$539.68	$30.50
	2	$750.24	16,489	17,603	278.67	-205%	278.67	12%	-$1,535.58	$86.78
	3	$837.17	16,489	17,672	295.84	-217%	295.84	12%	-$1,819.05	$102.79
	4	$699.45	16,489	17,712	305.92	-225%	305.92	13%	-$1,571.63	$88.81
Market	**Interval**	**Price**	**FMM LAP schedule (MW)**	**RTD LAP schedule (MW)**	**Imbalance (MWh)**	**Imbalance (percent of total)**	***Absolute imbalance (MWh)***	***Abs. imbalance (percent of total)***	**Weighted LMP (imbalance)**	**Weighted LMP (abs. imbalance)**
5-minute market	1	$124.14	17,513	16,102	-117.65	86%	117.65	5%	$107.27	$6.06
	2	$116.84	17,513	16,014	-124.93	92%	124.93	5%	$107.21	$6.06
	3	$117.10	17,513	16,118	-116.28	85%	116.28	5%	$100.01	$5.65
	4	$123.25	17,603	16,187	-118.00	87%	118.00	5%	$106.82	$6.04
	5	$139.35	17,603	16,371	-102.73	75%	102.73	4%	$105.15	$5.94
	6	$198.32	17,603	16,385	-101.54	75%	101.54	4%	$147.90	$8.36
	7	$165.33	17,672	16,428	-103.69	76%	103.69	4%	$125.92	$7.12
	8	$340.59	17,672	16,554	-93.16	68%	93.16	4%	$233.04	$13.17
	9	$238.42	17,672	16,572	-91.69	67%	91.69	4%	$160.56	$9.07
	10	$468.10	17,712	16,570	-95.20	70%	95.20	4%	$327.30	$18.50
	11	$468.10	17,712	16,503	-100.79	74%	100.79	4%	$346.52	$19.58
	12	$467.97	17,712	16,428	-107.08	79%	107.08	4%	$368.04	$20.80
	Min price:	$116.84		***Total imbalance (MWh):***	**-136.15**	***Total abs. imbalance (MWh):***	**2,409.31**	***Hourly weighted price ($/MWh):***	**-$3,230.20**	**$435.22**
	Max price:	$837.17								

Minimum and maximum of prices across the hour

Total imbalance across the hour (sum of MWh imbalance from day-ahead to 5-minute market schedule)

Total *absolute* imbalance across the hour

Hourly imbalance-weighted real-time price. This is outside of the range of the minimum and maximum price across the hour, so CAISO instead uses the absolute weights to settle load imbalance.

Hourly *absolute*-imbalance-weighted real-time price.