Price behavior in the California ISO Balancing Energy Market.

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Table of Contents

Introduction

The presence of price spikes in any market conveys little real information about that market. Price spikes are a manifestation of an underlying condition and it is the circumstances that cause price spikes that convey true information about the market and how it works. Since the demise of the Power Exchange during the energy crisis the CAISO has operated a real-time balancing market. Unlike day-ahead markets, which are relatively stable, balancing markets are by nature somewhat volatile. Price spikes in a balancing market are common, but can still have a number of different causes. The purpose of this report is to describe the nature of price spikes in the CAISO market and to come to some conclusions as to their legitimacy, for clearly not all price spikes are equally valid. Only by digging into the circumstances surrounding these price spikes can any conclusion be reached. To this end this report does three things;

1. It describes the nature of the balancing market
2. It analyzes the pattern of prices spikes
3. It digs into the context of the price spikes to reveal the smaller details that are often the root cause of more distant phenomenon.

Nature of the Balancing Market

The California ISO balancing energy market functions as a means for ensuring that the amount of energy generated in the CAISO control area matches the amount of energy consumed on a minute-by-minute basis. It is the third in a series of four processes that occur successively closer to the time of actual operation and are responsible, in aggregate, for providing the correct amount of energy to consumers at all times. The first two processes are the day ahead and hour ahead scheduling periods, during which market participants schedule energy that is contracted for bilaterally, and which typically matches the actual demand within a range of two to three percent. The fourth is AGC or Regulation, which provides the final level of matching but it is technically infeasible to provide clearing markets for regulation energy. Instead the regulation reserve capacity is cleared using a single price auction, and the regulation energy is paid the clearing price from the balancing energy market, which is the third process.

The California ISO historically has not participated in or influenced the bilateral markets, except from the standpoint of managing transmission congestion and providing services related to reliable operation of the grid. Rather the CAISO has managed the balancing energy market. This market has two flavors, namely an hourly market conducted at the intertie points with neighboring control areas that is paid-as-bid, and a five-minute market for internal generators that utilizes a single price auction. Together these markets allocate energy (either incremental or decremental) to match the load, given the more accurate predictive capabilities available when forecasting only 10 minutes ahead.

Balancing energy is settled at a market price determined by the most expensive energy that is dispatched by the system in any given interval using a uniform price auction.

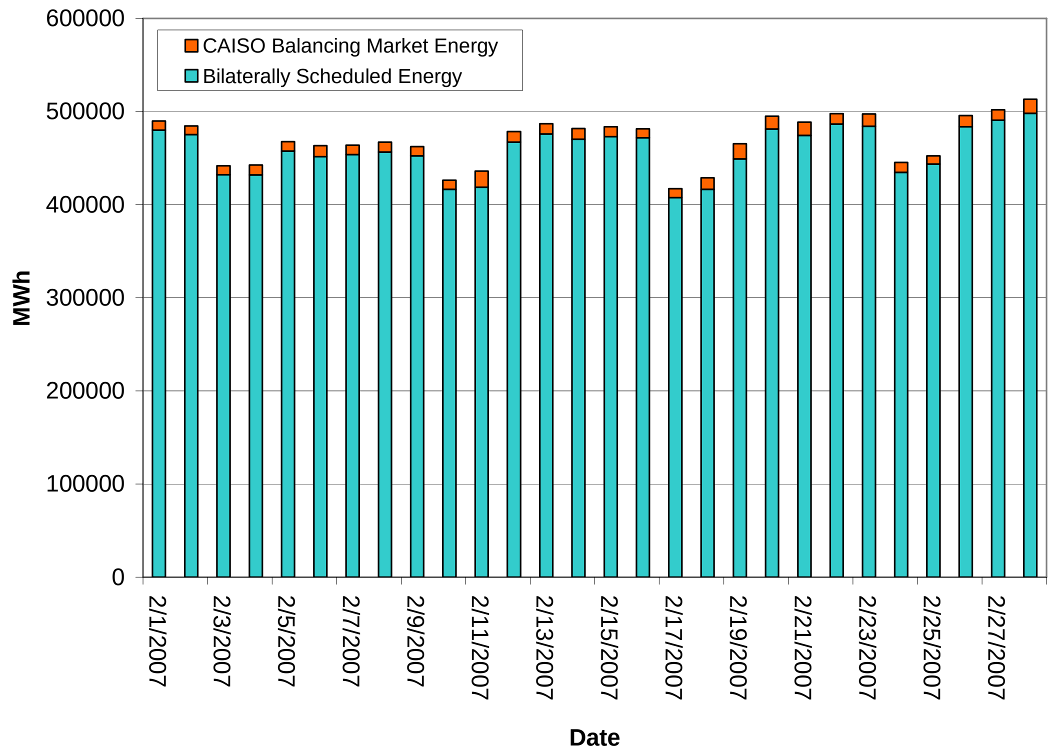
Due to the fact that a number of physical and market forces can affect the short term availability of energy from market resources, the price behavior of the market is complex. It is expected that a well-designed market should produce prices indicative of both the relative scarcity or abundance of the product and the sensitivity of the demand to variations in price. It is important to note that the purpose of a market is not to produce low prices *per se*. The strength of a market-based system lies in the fact that it reflects relative scarcities and thus incents the correct behavior. Thus price excursions that reflect relative scarcities are a desirable feature of a market and are consistent with the market framework. A well-designed market will, in the long term, produce prices that are **on average** less than other comparable production systems, such as cost-of-service production.

Several aspects of the balancing energy market contribute towards a propensity for price volatility.

- Unlike other products there is practically no storage capacity for electric energy, making it impossible to smooth out inter-temporal variations in demand by stockpiling in times of abundance.
- Demand is almost completely inelastic as end-users cannot see the real-time price of energy. This leaves the burden of adjustment completely on the supply side. Thus the market dispatch process will allocate sufficient energy to meet the predicted demand without regard to the price, and prices will increase to the administrative cap if necessary. The current administrative cap ($400) is a great deal less than the Value of Lost Load (VoLL) which, although difficult to calculate, is often proxied at around $10,000/MWh. The inelasticity of the demand curve is a logical result of the absence of real-time price signals to end users. Essentially the price signaling mechanism is truncated at the wholesale level, and the burden of price response is left wholly on the supply side.
- The amount of energy that is available on any day is often contingent on unit commitment decisions and maintenance schedules determined the day before. The market accounts for a very small percentage of the total energy volume produced and therefore a limited amount of capacity is available to meet unexpected system changes such as generation outages or other impacts If the weather or load forecast varies from expectations by a margin greater than anticipated then it is often already too late to bring units or transmission lines into service due to lead times. Those fast-start units that can be brought on-line are often expensive to operate and may also require higher prices in order to recover fixed costs over a limited daily operating cycle.

The daily proportion of energy dispatched in the balancing energy market relative to scheduled energy is shown in
Figure 1 below for the month of February. Although the proportions do vary from day to day and month to month, this figure is representative. Taken as a monthly average, 2.5% of the overall energy consumption in the control area was transacted in the balancing energy market[1]. This figure is rarely over 5%.

Figure 1: Percentage of Balancing Energy vs. Bilaterally Scheduled Energy, February 2007



Analysis of Price Spikes

Price spikes have a number of characteristics beyond the high price. A price spike can be of varying duration. Thus a single interval price spike is as much a spike as a multi-interval spike, though the financial effects are different orders of magnitude. Figure 2 indicates the number of occurrences of periods of prices

[1] The balancing energy market encompasses both incremental dispatch (energy purchased by CAISO from scheduling coordinators to cover a deficit in bilateral schedules) and decremental dispatch (energy sold by CAISO to scheduling coordinators). For the sake of simplicity, both incremental and decremental energy are considered as positive transactions in Figure 1, This somewhat overstates the percentage of balancing energy actually consumed by end users, but is adequate to impart a sense of the relationship between the bilateral and balancing markets. If the net balancing energy volume was presented instead, the overall percentage would be smaller, and could be either positive or negative.

above $250 from January 2006 until the end of February 2007, grouped by event duration in dispatch intervals. It is immediately evident that the largest group of high price events are instances lasting a single interval. Events lasting for two intervals are also quite common, while extended periods of high prices occur less often. When taken as a percentage of the total number of events, those with duration of 1 or 2 intervals make up 74% of the total. As a percentage of intervals, however, only 44% of the high priced intervals occur in conjunction with events lasting for two intervals or less.

Figure 2: Number of Occurrences of Prices Above $250, Grouped by Duration in Intervals - January 2006 to the end of February 2007

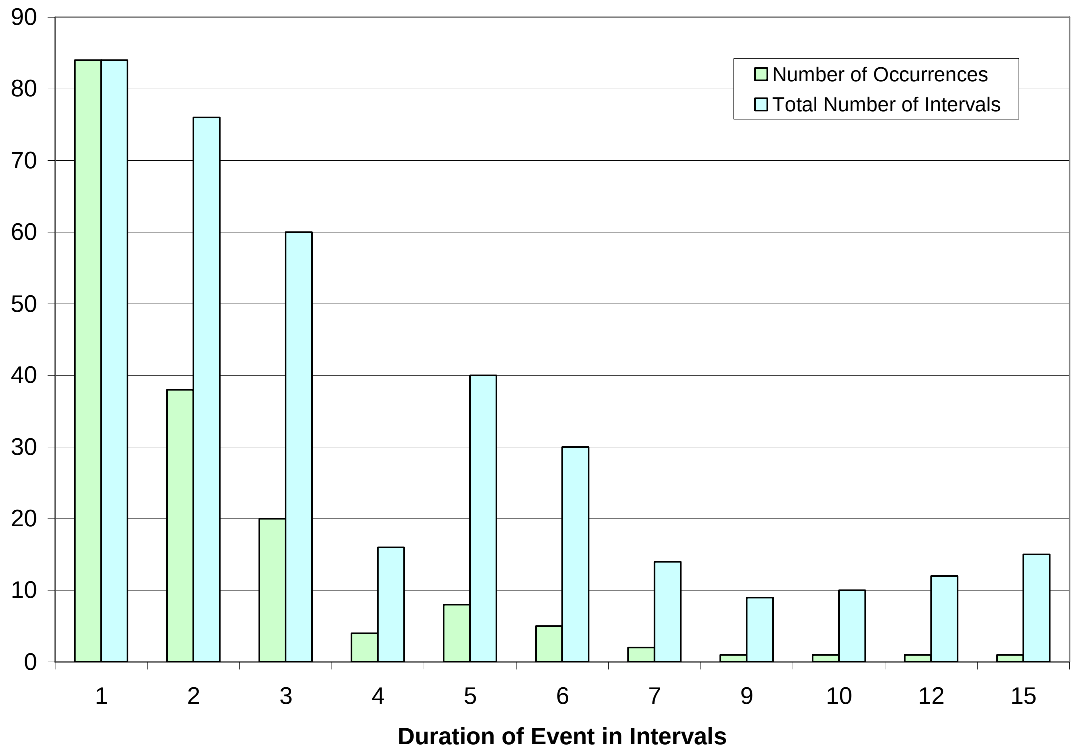


Figure 3 groups the occurrence of elevated prices by the interval in which the first high price occurs. This shows that the preponderance of short term price elevation occurs beginning in interval one, and most spikes that begin in interval one are of short duration. This indicates that the beginning of the hour is a time when there is a particularly high demand on the resource fleet to change its output.

Figure 3: Occurrence of Prices above $250 per Interval, August 2006 to February 2007

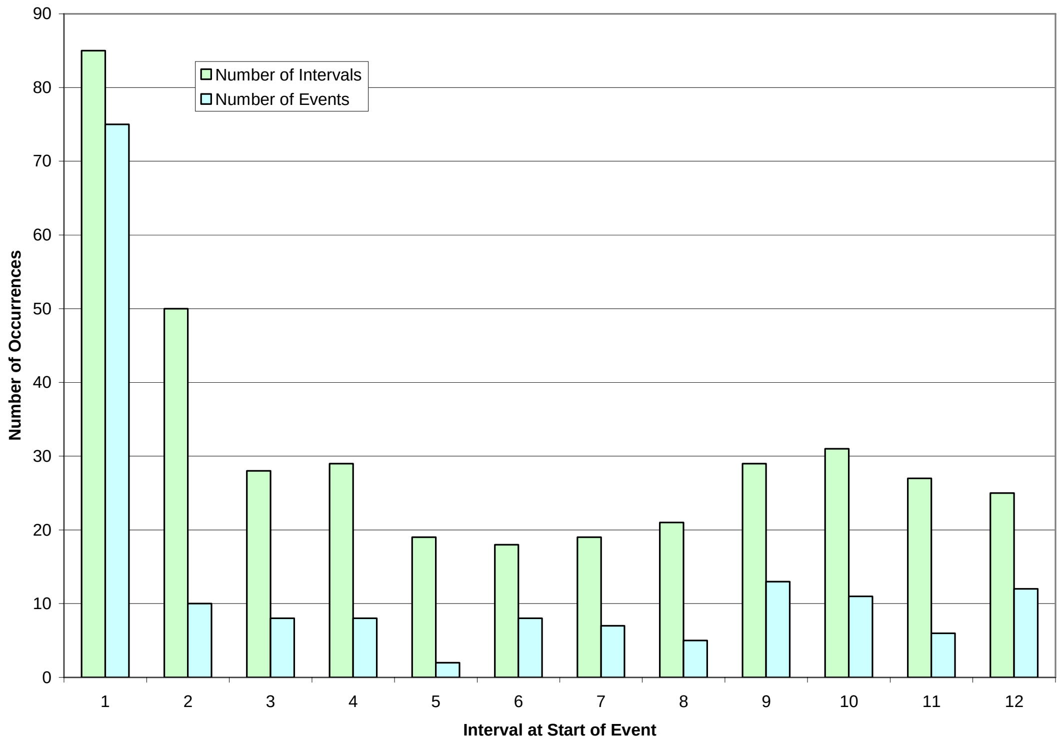
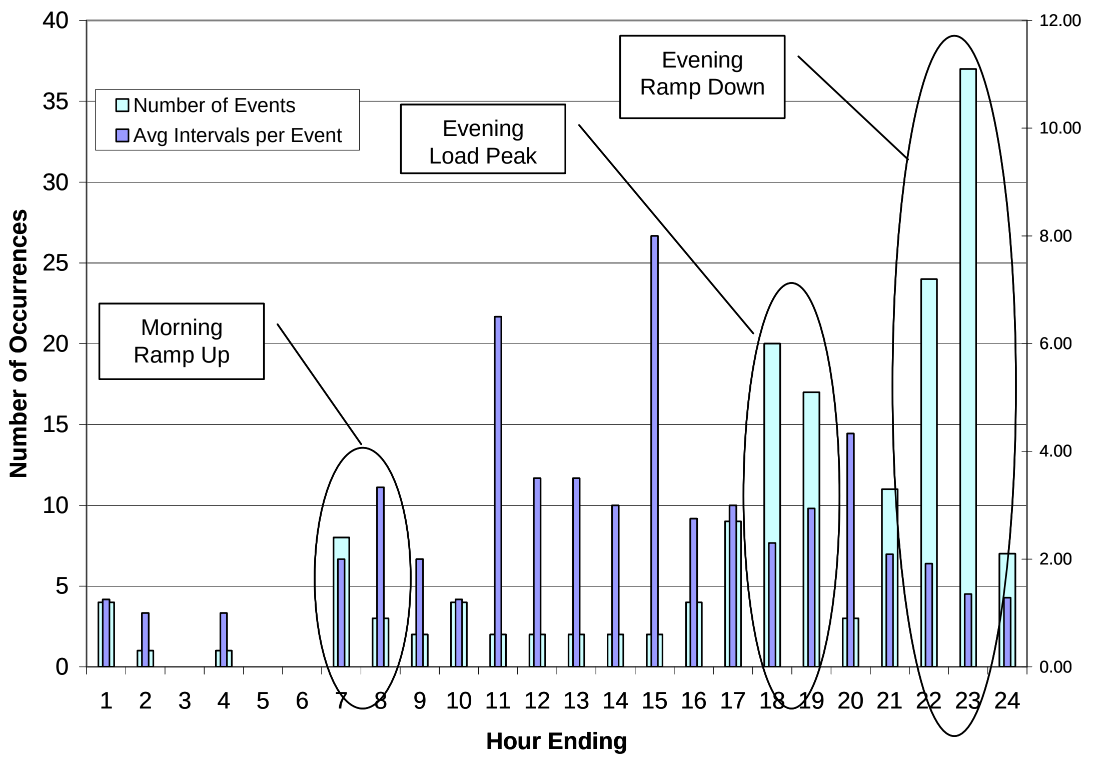


Figure 4 looks at the hours in which most occurrences of elevated prices occur, and the average duration of occurrences in each hour. As the figure makes clear, instances of price elevation that occur in the afternoon hours tend to be fewer but of longer duration, whereas the events that occur during the ramp times are more numerous but of shorter duration, particularly during the late evening ramp-down. During this time of evening, both generation and interchange schedules change significantly from hour to hour

Figure 4: Occurrence of Prices above $250 per Hour, August 1 2006 through Feb 28, 2007



Summary

Analysis of the price spikes shows two patterns. The longer duration price spikes, typically in the afternoon as the peak approaches, are caused by grid events. These are price spikes that reflect relative scarcities and are a normal function of a balancing market[2]. They would also more naturally occur in the afternoon as that is often the peak, especially in the summer, and when units are stressed they are more likely to fail.

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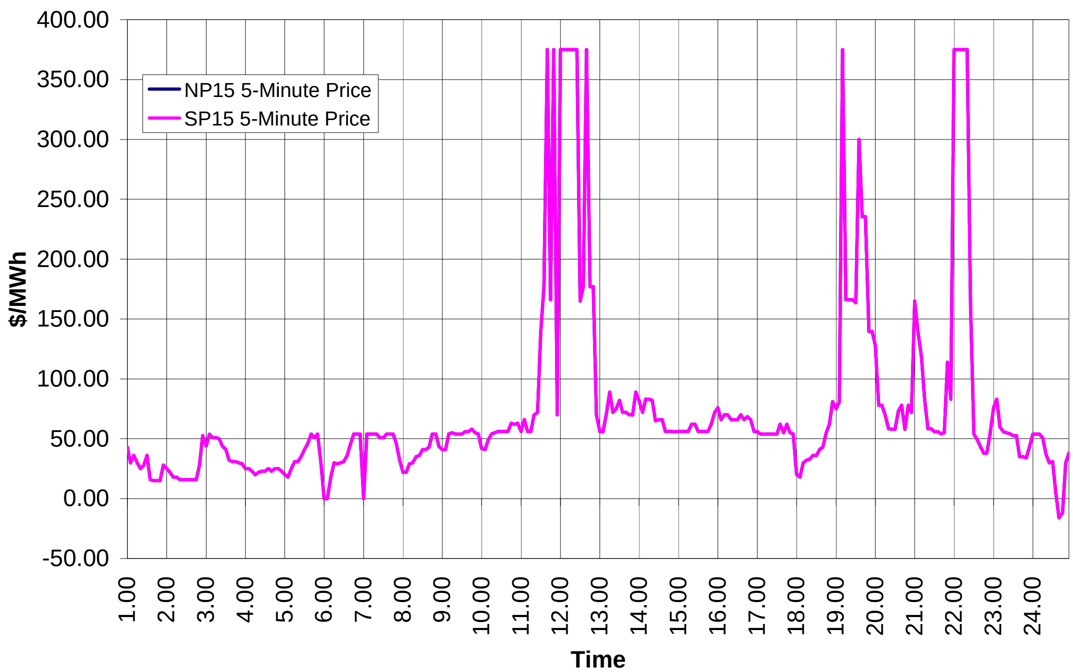
[2] These long duration price spikes can be mitigated. Generation units can be constrained on and used to lessen the intensity of the price spike, or more regulation can be bought. There are a number of drawbacks to these two approaches. Constraining on extra units pushes the true costs of the price spikes out of the balancing energy market and into the unit commitment cost area (essentially Startup and Minimum Load costs). These costs are not as visible, and preliminary analysis indicates that the cost of constraining on these units would itself be expensive, would only partially mitigate the price spikes, and would depress prices in the balancing energy market. This is not a desirable outcome. Similarly buying more regulation would also partially mitigate the price spikes, however buying more regulation is costly as price spikes are difficult to predict, hence the overall amount of regulation procured would have to be increased. Also buying more regulation is somewhat inappropriate as this is not a regulation issue, but a balancing energy issue.

By way of example consider the graph below which shows the Balancing Market prices on February 19th 2007. On this day there was a grid event where several 230kV transmission lines were out of service beginning in midmorning in the area south of the Big Creek complex. In addition a large combined cycle unit had a forced reduction in output starting in Hour Ending 10, and a second unit was de-rated just prior to the start of Hour Ending 22. This resulted in sustained price spikes in midmorning and late evening, as the CAISO dispatched around these events, and it is an example of the market working the way it was designed to work. The price spikes where the issues are not as clear cut typically occur around the morning and evening ramps. February 19th had an example of this sort of a spike in Hour Ending 19. This is the result of the rapidly changing system load around the evening peak, in conjunction with the load forecast running somewhat short of actual load in the previous hour. This in turn placed a rapidly changing demand on the resources providing balancing energy, resulting in characteristic short duration price spikes. This type of spike does occur around the evening load peak, but occurs more consistently during the morning and evening ramps.

Figure 5: Real Time Price Data, February 19, 2007



Price deviations in the balancing energy market are observed to be roughly of two types;

- Very short spikes that typically reflect a momentary unavailability of energy due to the physical inability of system resources to increase their power output beyond a certain maximum rate. In these cases one typically observes one or two intervals during which the price rises suddenly and then drops back to more moderate levels. This is a consistent pattern.

- Price elevations that extend over longer durations and are more likely to be due to actual scarcity, either due to insufficient forward scheduling, unanticipated weather fluctuations or equipment outages. In these cases the market prices accurately reflect the increased demand on balancing energy. These elevated prices can be properly viewed as characteristic of a well-functioning market.

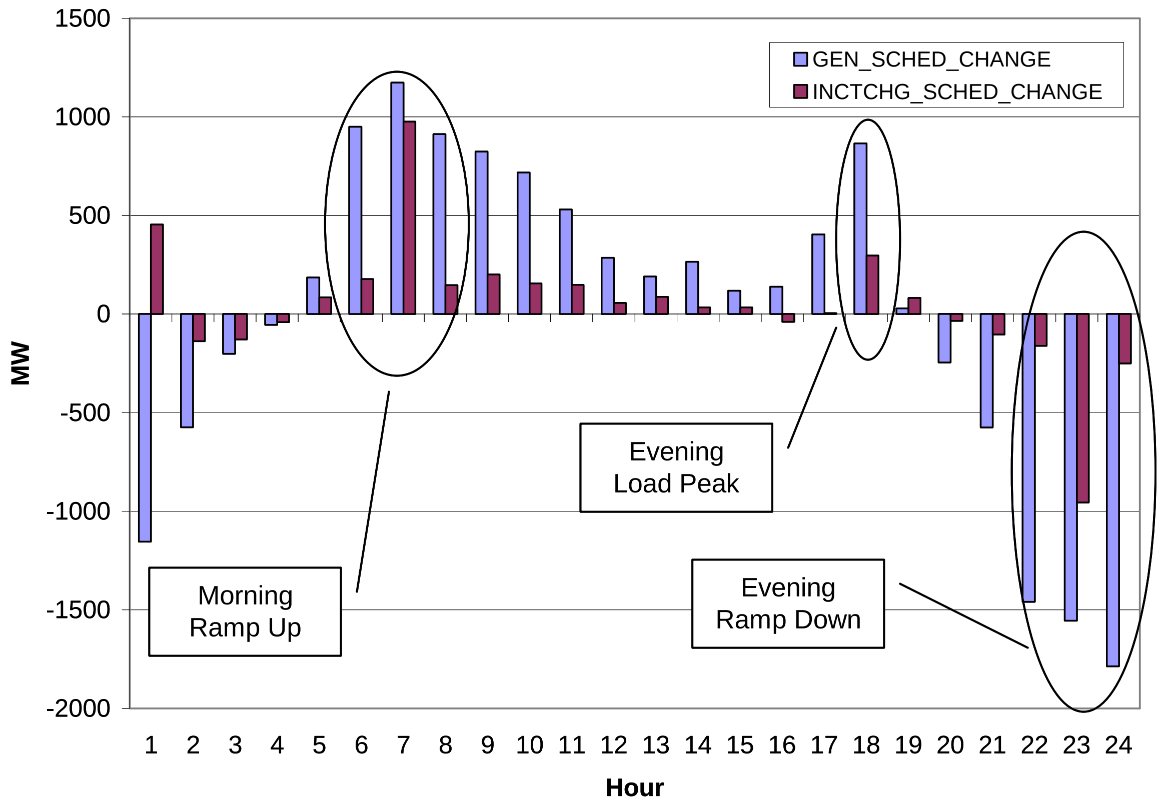
The importance of these sustained price excursions varies with the cause. Price excursions caused by unexpected events (equipment problems, vagaries of the weather) are less important as they are inherently legitimate. The purpose of having a balancing market is precisely to deal with these imbalances, so this type of price excursion represents an appropriate market response. Those price excursions that are caused by events over which the CAISO has some control are more important as the CAISO has an obligation to run the market as efficiently as possible, and in addition, grid reliability is improved by efficient markets. Thus some of these spikes may not be underpinned by the legitimacy that is conferred by grid-related events. Put simply; unavoidable grid-related events confer legitimacy on price spikes and these sorts of events are a challenge for grid operations. Price spikes that are avoidable are inherently less legitimate, and consequently attract considerable attention from CAISO Market Monitors, Designers, and Systems Analysts. This paper concerns itself specifically with the latter aspect, where price excursions might be avoidable. The term "legitimacy" thus specifically relates to whether or not an event is avoidable from the CAISO's perspective. The express purpose of the examples listed below is to illustrate the complexity of these issues and to try to come to some conclusions regarding the nature of price excursions, especially those over which the CAISO has some influence.

Price Spikes and Legitimacy: Some Examples

Price Spikes and the Ramps

By way of example consider the ramping spikes that are a perennial feature of our markets. The morning and evening ramps occur around Hour Ending 7 (i.e. between 6 am and 7 am), and then later in the evening around Hours Ending 22 and 23. Figure 6 shows the average schedule change per hour of all interchange and all generation, averaged over a period of months. It can clearly be seen that the large schedule changes that occur in the morning, late evening and peak hours (shown encircled in Figure 6) correlate well with the short duration price events, particularly during ramp down. A contributing factor in the volatility of price at that time is that fewer resources are available in the late evening to respond to the differences between scheduled generation and load that occur during ramp-down. There are a number of factors that contribute to the inefficiency of these price spikes.

Figure 6: Changes in Hourly Energy Schedules per Hour, Generation and Interchange



The Load Shape

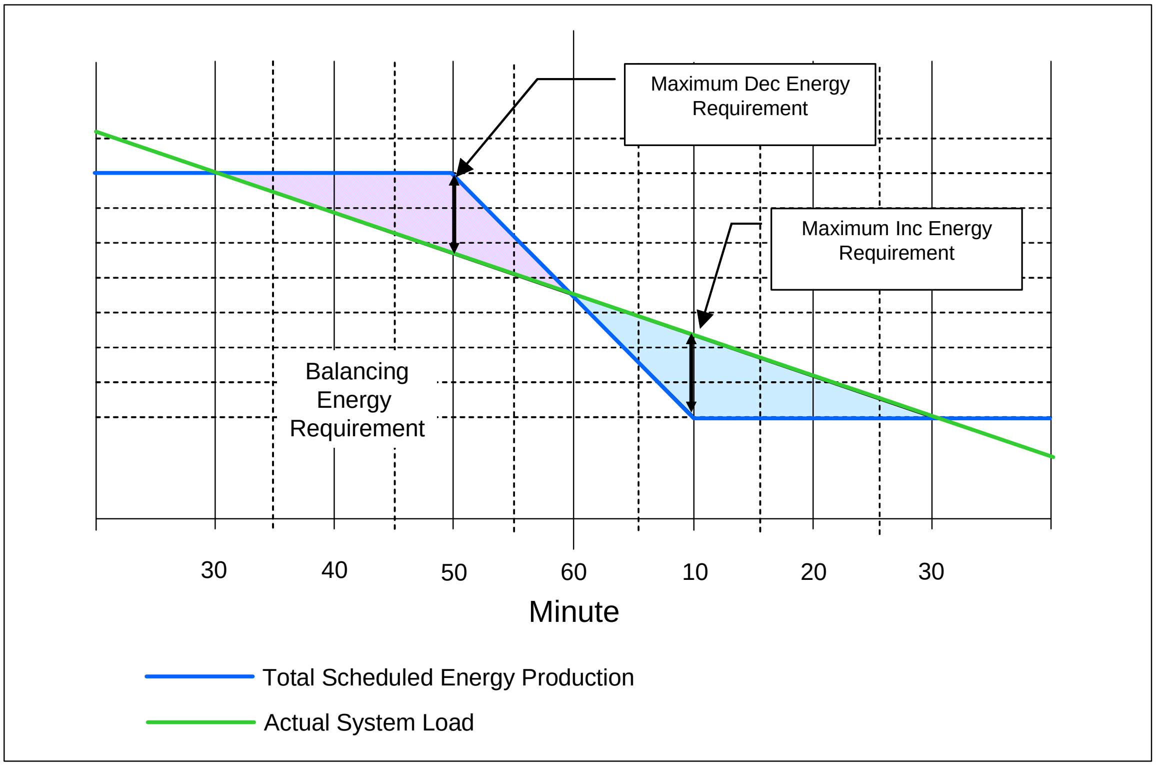
The load shape is fixed in the short term, but over the long term it is amenable to price signals if those signals exist. Many programs are in place in California that allow for reduction in demand under circumstances where system reserves are depleted. Such programs are valuable components available to CAISO for maintaining system reliability when there is a danger that demand will exceed supply. To the extent that these programs affect demand in the balancing energy market, they have a significant effect on prices. Strictly speaking, however, they are not price responsive. Interruptible load contracts are typically subject to contract provisions that are formulated in advance, and triggered when the system operating reserve falls below levels specified by the Western Energy Coordinating Council regulations. As such, the load reduction is not price responsive, but does tend to reduce prices in the market when it is triggered. In the present regulatory environment, real time pricing is not applied to retail energy consumers, so the opportunity to develop demand reduction in response to elevated balancing energy prices is zero. Until load becomes price responsive the burden of adjustment will fall on the supply side. Clearly the absence of price signals exacerbates price spikes and this will continue into the future.

Institutional Rigidities

As Figure 3 illustrates, the great majority of short-duration price elevations occur in Interval 1, that is, immediately after the turn of the hour. To understand how this arises, it is necessary to understand how bilateral energy contracts are delivered. A typical energy contract, and in particular a contract that is delivered from outside the CAISO control area, is specified in terms of hourly energy amounts that are to be delivered per hour. Since the resources that deliver the energy cannot charge their output instantaneously, there must be a period of time between hours during which the output of the generator is changing from one value to the next. The WECC specifies the ramping profile for energy transmitted between control areas as being equal to the contract MWh value between minutes 10 and 50, and ramping linearly from one hourly contract value to the next over the 20 minute interval from minute 50 of one hour to minute 10 of the next. This convention is convenient from the standpoint of accounting and controlling tie line flows, but it does not match the evolution of system load, which varies more or less smoothly and continuously from one hour to the next. The consequence of this type of ramping is that even if the total amount of energy contracted in the bilateral forward markets agrees exactly with the load, there will be an instantaneous mismatch between load and generation over the course of each hour because the load varies at a different rate than the bilaterally contracted generation. It is up to the balancing energy market to make up the minute-by-minute mismatch.

Figure 7 illustrates a ramp-down situation in which the bilaterally contracted energy amounts are exactly correct. In this example the actual load agrees exactly with the scheduled production at minute 30 of each hour. Due to the differences between the ramping of standard energy contracts and the actual variation in the load, however, balancing energy is still required to ensure that production and demand are matched in each five-minute interval. The balancing energy requirement changes from strongly decremental at minute 50 of the first hour to strongly incremental at minute 10 of the second hour. This is due to the fact that the scheduled energy production is significantly above the actual load in the latter part of the first hour, and significantly above it in the first part of the second hour. This rapidly changing balancing energy dispatch is due to the mismatch between the change in demand vs. the production profile of standard forward contracts, and is most pronounced during times of rapidly changing demand, that is, during the evening and morning ramps. It is this phenomenon that is primarily responsible for the occurrence of spikes at the beginning of Hour Ending 23, and at other times when the system demand is changing rapidly. The important conclusion to take away is that even when everything is working as intended balancing energy is required to match demand to supply. This phenomenon is institutionalized in the sense that WECC interchange conventions require hourly contracted energy to be delivered with a 20-minute centered ramping profile.

Figure 7: Balancing Energy vs. Bilateral Energy



Since the ramping profile is a WECC convention, it cannot be unilaterally altered by CAISO without agreement with WECC, neighboring control areas and market participants. Moreover, internal generators that do not participate in the CAISO balancing energy markets are also required by the CAISO tariff to follow the same 20-minute ramping profile. It is quite likely, however, that lengthening the hour-to-hour ramping times for bilaterally contracted energy would mitigate the short-duration price spikes that are seen during the morning and late evening hours. Clearly however this ramping rigidity is responsible for many of the price spikes in the balancing market.

Legitimacy

This example highlights the legitimacy issue, for the question then becomes whether or not this characteristic of the market legitimates the price spikes, and it is particularly interesting as there are two classes of suppliers here, namely hourly intertie suppliers following WECC conventions and internal generators following CAISO rules. WECC rules are amenable to change, but only with difficulty. Further this issue is particular to the CAISO as California is more import dependent than neighboring control areas. California is the main import sink in the west, and our problem is only a minor inconvenience when distributed amongst the various other control areas[3]. Thus this would be difficult to change, and hence price spikes that result from this practice could be classified as legitimate. Making the same argument for internal generators is much more difficult as the means to change the procedure is available to the CAISO, and the internal generators contribute to this problem in proportion to their share of the net schedule change for any one hour.

Software Issues

Software issues are extremely important when analyzing markets, for it is the software system that operationalizes the market theory. Ideally the software modeling would be a straight pass-through and would not affect the way the market clears. Unfortunately that does not always happen. Rather there are occasional disconnects between the design and the implementation. This is true in our current real-time software system and is best illustrated by way of example.

Interchange Modeling

The method by which generation and particularly interchange is modeled can contribute to cyclical variation in the volume of balancing energy dispatched around the hourly transitions. In particular the change in interchange energy flows is modeled as an hourly step change[4] in the Phase 1B dispatch engine, which creates quite a sharp transition beginning in interval 1 as the schedule change occurs. Changes in scheduled generation also occur at that time, but they are modeled differently, being represented as 20-minute ramps beginning ten minutes prior to the hourly change and ending 10 minutes after. The step changes in interchange schedules appear to be a significant driver in the price spikes that occur in the late evening hours. This condition is exacerbated to a

[3] It is interesting to note that the Eastern Interconnection does not have uniform ramping procedures. In PJM for example internal units as well as energy scheduled over the interties is done in fifteen minute increments, not hourly increments. Thus it is possible to schedule energy from 14:15 to 14:30. This is not possible at the CAISO, and indeed some other control areas in the eastern interconnection also follow the hourly scheduling protocol that the CAISO does. The ramping convention at PJM is also different in that it is what they term a ten-minute straddle, namely five minutes on either side of each fifteen minute scheduling period. This more granular approach is clearly preferable to anything in the WECC or the CAISO as it decreases the swings in the balancing market by allowing schedules to more closely track load. Such an approach would most likely have significant benefits as it would reduce the “blockiness” of schedules, lessen the ramping requirement in the balancing energy market and most likely reduce the number of price spikes.

[4] Interchange energy flow is not modeled with a 20-minute ramp in the current implementation of the RTMA software. Rather, when calculating the amount of energy required from balancing energy resources, the RTMA calculation assumes that the tie line flows remain at their hourly scheduled quantity until the end of the hour and then jump immediately to the new schedule at the beginning of the next hour, which means that the total interchange value changes abruptly from the previous hour’s value to the next hour’s value starting in dispatch interval 1 of each hour.

certain extent by the underestimation of the ramping at that time, an issue that is treated in the following section.

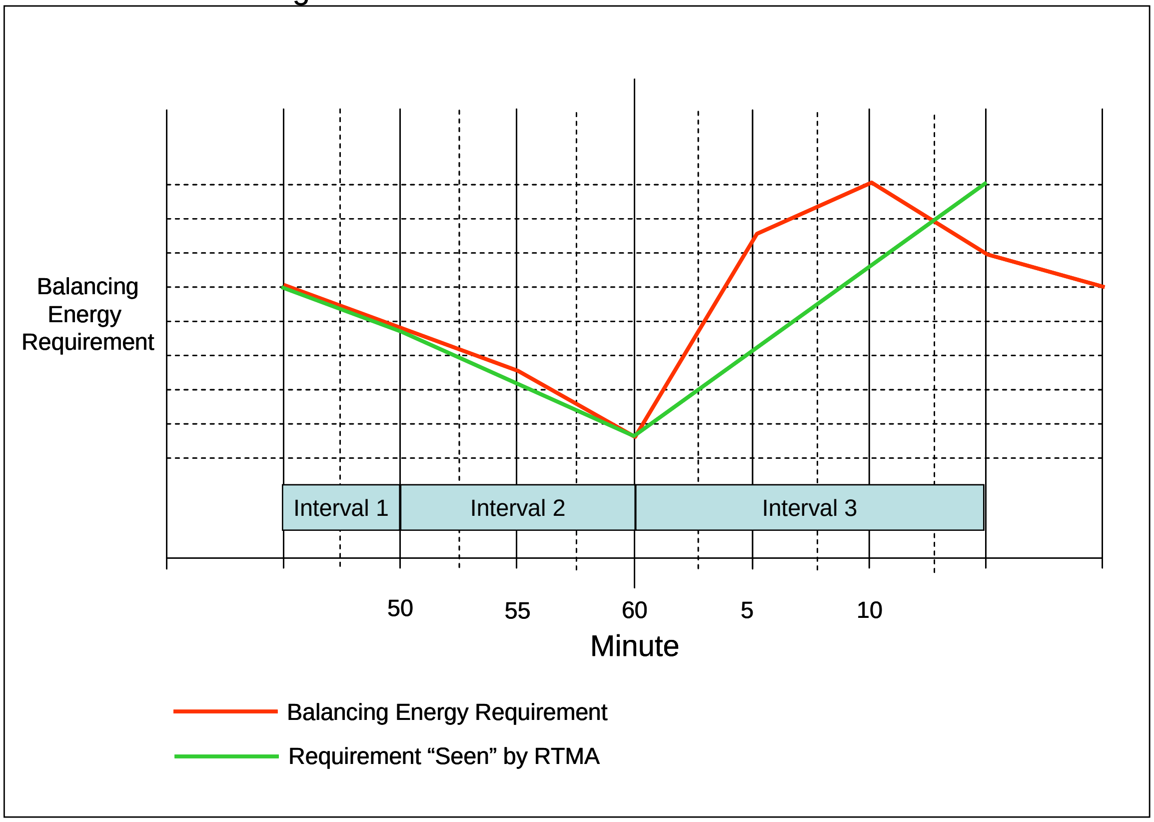
Due to changes in the way that interchange schedules are modeled in MRTU, and in particular the modeling of interchange as varying on a 20-minute ramp rather than as a step change, the schedule transition should be smoother and less prone to price variation in the new software. MRTU will model the standard WECC twenty-minute ramp, with the result that the balancing energy requirement should agree more closely with actual flows, reducing the incidence of short duration price spikes.

Ramp Underestimation

Finally, although the Phase 1B dispatch engine does look ahead at the forecast load, interchange and generation, it does so in a way that can underestimate the change in some cases. The RTMA dispatch engine that is presently used in Phase 1B uses a variable time interval for looking ahead to meet forecast load[5]. The first time interval is always 5 minutes in duration, but intervals in the future time horizon are longer, as the figures below illustrate. Figure 8 shows the RTMA horizon, which indicates that although there is a significant increase in balancing energy required at the top of the hour, RTMA will not recognize the full magnitude or steepness of the requirement until interval 12 of the prior hour, when its first 5-minute interval will show the steep increase. The green trace shows the expected balancing energy requirement as seen by RTMA for the dispatch calculation running at minute 40. Due to the shape of the requirement (which is typical for a ramp-down mode) the green line misses the peak energy requirement.

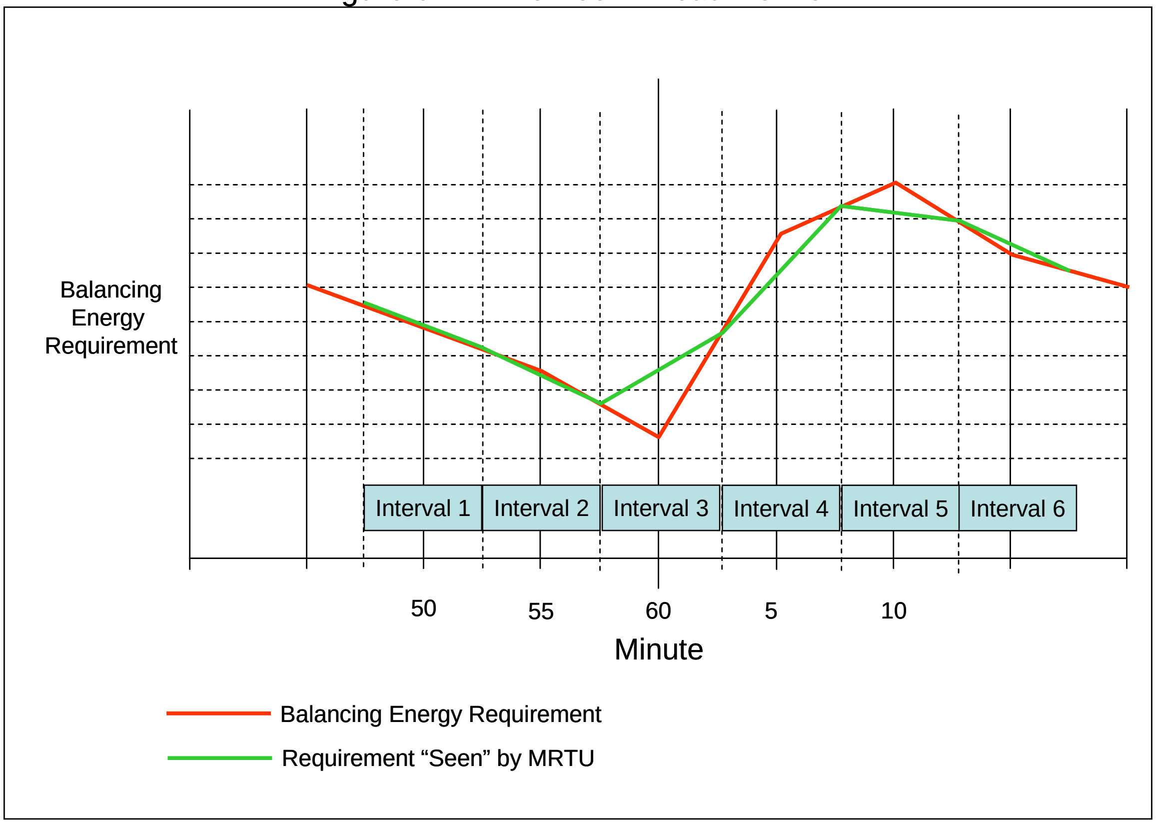
[5] During the design of the look ahead functionality for 1B it was originally decided not to have a variable horizon, however this was changed due to performance requirements. The variable horizon decreases the number of intervals and thus decreases the time to solve. This was seen as a benefit. The interaction between the variable time horizon of the look-ahead feature and the frequency of price spikes was not foreseen.

Figure 8: RTMA Look-Ahead horizon at T-15



Contrast this to Figure 9, which illustrates the MRTU look-ahead. The MRTU look-ahead does not use a variable horizon, rather the real-time dispatch engine looks ahead in 18 increments of five minutes each. As can be seen, the MRTU method much more accurately captures the requirement at the turn of the hour. This feature should significantly mitigate the occurrence of short duration price spikes.

Figure 9: MRTU Look-Ahead Horizon



Legitimacy

Given our current RTMA system the question again needs to be raised as to whether or not price spikes which are related to these modeling difficulties should be seen as legitimate, bearing in mind that the distinction between legitimate and not-legitimate is sometimes more appropriately measured along a continuum rather than as a binary outcome. In the short term price spikes engendered by these modeling difficulties should probably be classified as legitimate, however in the long term these modeling issues can be solved with subsequent releases and in this case MRTU does have a solution to this problem.

RTMA and the Predispatch

The predispatch is an issue which has recently received more attention, and it highlights an inefficiency which has its root cause in the way pre-dispatch bids are modeled in the software and the way in which they are used by market participants.

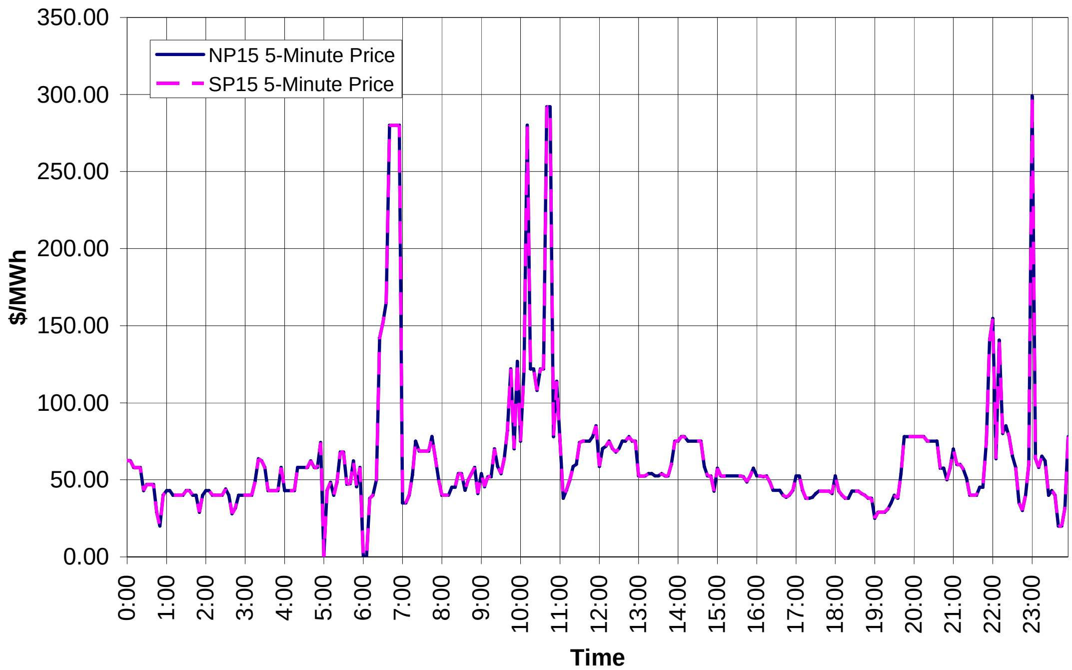
One of the purposes of using a central market clearing mechanism is that such procedures are seen as more efficient than a plethora of bilateral agreements. RTMA is an optimization designed to deliver that result, which can be characterized as a least-cost solution subject to reliability constraints. RTMA acts to this end by performing the market clearing mechanism when it clears incremental bids against decremental bid. One of the problems of a bilateral market is that price discovery is difficult. Thus it is both likely and common that some participants are prepared to sell energy at prices lower than others are willing to buy it. Thus one SC may offer generation to the ISO (an inc) at $50, whilst another SC wants to buy generation from the ISO (a dec) for $80. In this case there is a $30 difference that RTMA is programmed to capture. This aspect of RTMA is called “Market Clearing” and its benefits offset the cost of balancing energy for Load Serving Entities. This market clearing mechanism can work between intertie schedules and other intertie schedules, or between intertie schedules and internal generation, or even just between internal generators.

The benefit malfunctions due to modeling incompatibilities. For the trade-off to work RTMA has to be able to dispatch both incs and decs and have a reasonable assurance that Scheduling Coordinators will deliver on the bids that they have submitted. For internal generators this is what happens as if an internal generator fails to deliver on a bid that is dispatched then it is assessed an imbalance energy charge approximately equal to the cost incurred by the ISO to replace the power it did not deliver. This can be expensive especially if the absence of that generator’s energy inflates the real-time price, as the charge then scales to that figure. This mechanism keeps internal generators responsive. Unfortunately this is not the case with intertie bidding. If an SC submits an intertie bid, is dispatched, but then decides not to deliver that energy there is no financial penalty assessed. Thus the bidding rules for internal generators and intertie generators are different.

The problem that emerges is that RTMA registers all of these intertie bids and performs its market clearing presuming that this energy will be delivered, when in reality it is often the case that the intertie dispatches are not delivered. RTMA thus models the intertie bids as a binding commitment, not an option, the same as internal generators, and when RTMA was being developed it was presumed that the intertie generators would face a similar penalty structure to the internal generators, so at the time this was a reasonable assumption. Unfortunately this initiative to enforce the intertie bidding practices was part of a broader Uninstructed Deviation Penalty (UDP) initiative which was shelved.

This mismatch between the way RTMA sees the dispatches (i.e. binding) and the way they are used by Scheduling Coordinators (options) plays havoc with the optimization. What happens is that RTMA will perform its market clearing process and then one side of the clearing process will fail to show up. On April 3rd 2007 there was a price spike in Hour Ending 7 which breached $250. Part of this price spike is due to the predispatch problem. As is usual the RTMA software performed a look ahead and found some opportunities to clear the market. In particular the CAISO sold 962 MW of energy to pre-dispatch bidders for prices ranging from $70.27 to $95.00, which is a weighted average price of $78.89. During this same hour RTMA was expecting 375MW of incremental dispatches that did not arrive. These bids were priced between $60.00/MWh and $70.00/MWh, for a weighted average price of $65.98/MWh. RTMA was performing according to its specifications, namely buying low and selling high. Due to the declines on the inc bids RTMA had to rely on the internal generators to make up the difference. Thus the optimization was selling at $78.89 and supplying at least part of the energy at prices exceeding $250 because the inc intertie bids (at $65.98) did not show. In this case RTMA was effectively buying high and selling low, a surefire way to lose money. Furthermore the fact that there was a price spike is undoubtedly partly related to the fact that these intertie dispatches were declined, as RTMA had to dispatch 375MW deeper into the stack that it initially planned to. This results in a financial loss which is borne by Load Serving Entities, not by intertie generators. More importantly it degrades the optimization such that the solution is clearly not optimal

Figure 10: Balancing Energy Price – April 3rd 2007



Legitimacy

When one examines this particular occurrence the question again emerges. Is this instance a "legitimate" spike or a "spurious" spike. In this case clearly the spike is spurious, as it is related to enforcement and modeling issues which can be changed and not to grid events, which would legitimate it. Ultimately the disconnect between the way the software treats intertie bids (binding commitments) has to be reconciled with the way Schedule Coordinators treat intertie bids (options).

Conclusion[6]

The analysis shown here has clearly demonstrated that not all price spikes are equivalent. Although price spikes seldom have a lone cause the true importance of price spikes lies in the legitimacy of their origin. Price spikes caused by unexpected events clearly are legitimate and are part of the normal functioning of a healthy market. Once this has been determined no further analysis is needed. Price spikes rooted in avoidable circumstances however are much different. In this case price spikes that might be legitimate in the short term

[6] It should be noted that under MRTU the price cap rises from its current $400 to $500 upon go-live, followed by $250 increments on each one-year anniversary until it reaches $1000. Further the price cap under MRTU is a bid-price cap, not an LMP cap. Due to the way prices and schedules are optimized using distribution factors, LMP prices in the balancing market under MRTU can and will exceed the FERC-approved bid-price caps.

might well be illegitimate in the long term simply because something can be done to mitigate them, and it is this second class of price spikes that is worthy of further study. The examples explained here demonstrate three categories, namely something of questionable legitimacy, namely the pre-dispatch problem; something that is legitimate in the short term, but needs to be solved in the long term (and is being solved by MRTU), namely the way interchange schedules are modeled; and finally something which at the very least should be looked at once some of the larger redesign issues are taken care of under the MRTU program, namely the way internal generators schedule their units.