Market-Based Price Differentials in Zonal and LMP Market Designs

James E. Price

***Abstract*—The California ISO is redesigning procedures for scheduling, dispatch, and congestion management, which are critical to reliable, nondiscriminatory transmission service. The redesign implements Security Constrained Unit Commitment and Locational Marginal Pricing to reflect actual costs of delivering energy, using an accurate network model to price both congestion and losses. CAISO simulations of the market redesign are a unique opportunity to compare a) estimated LMPs if the redesign were in place during recent historical periods with b) actual conditions, as logged in operating records. The study uses market schedules and bids in an Alternating Current Optimal Power Flow simulation. Resulting LMPs are similar within current congestion zones, but price differences occur during high loads, reflecting actual changes in system conditions. The frequency and magnitude of LMP differences are consistent with the current market, suggesting that the increased market transparency will produce stable, predictable prices. Case studies demonstrate that optimization using SCUC and SCED, coupled with the state estimator, allows more appropriate responses to system conditions, improved utilization of transmission capacity, reduction in congestion costs, and enhanced system reliability.**

***Index Terms*—Electricity market, marginal pricing, network losses, optimization, power systems.**

I. Introduction

THE California Independent System Operator (CAISO) is in the process of redesigning the procedures by which it performs forward scheduling and congestion management. These are critical to the CAISO's core function of providing reliable transmission service on a nondiscriminatory basis. The centerpiece of the redesign, known as Market Redesign and Technology Upgrade (MRTU), is congestion management using a detailed model of the transmission grid instead of the highly simplified model used in today's zonal approach.

The last several years of operation have demonstrated the severe shortcomings of the CAISO's original "zonal" congestion management. As discussed in Section II, during recent years the resulting operational and cost impacts have become progressively higher as new generation has come on-line in congested areas of the transmission grid. The new design addresses these issues in order to improve grid reliability and efficient utilization of California's transmission and generation facilities, by producing more transparent price signals. Adding a day-ahead market to the existing real-time market will ensure that forward (day-ahead) schedules are fully consistent with actual real-time flows over the grid.

Before MRTU is implemented, the CAISO is conducting analyses to review its likely outcomes, by comparing a) estimated prices that would have occurred if the new market structure had been in effect during recent months with b) conditions that occurred under the existing zonal market structure during the same period. This is a unique opportunity to compare the pricing results of alternative market designs, as the required resources are dedicated to a detailed comparison between them, including the complete set of market bid data and other operational data of an ISO.

II. MRTU Background

MRTU will provide for a new congestion management system, and establishes a financially binding day-ahead market for trading and scheduling energy, a residual unit commitment process, a real-time market that includes an hour-ahead scheduling process, market power mitigation measures, and resource adequacy requirements. The day-ahead market will co-optimize energy and ancillary services procurement, subject to transmission and other operational constraints. Once the CAISO has established final day-ahead schedules, the CAISO will compare them to its projected load forecast, including forecasts for certain local areas, and secure additional resources through a "residual unit commitment" process.

The real-time market updates the energy scheduling and capacity procurement, using updated demand forecasts for the next 5 h, and knowledge of outages and other operating conditions. In both the day-ahead and real-time markets, scheduling priorities are recognized. These include priority uses such as supply schedules that maintain system reliability, use of pre-existing transmission contracts, and bids that are submitted as price-takers in an initial "scheduling run." Penalty prices for these bid segments are kept from affecting final market prices, though, by freezing the affected schedules and re-optimizing by setting prices in a "pricing run," using economic bids that are limited by caps and floors. Another instance where separate optimization runs serve different purposes is in the real-time market, where a real-time unit commitment process runs on 15-min intervals, and a separate real-time economic dispatch process runs on 5-min intervals to determine output levels. Further details of the market design are available at [1] and [2].

MRTU improves the CAISO's current market design in a number of ways. The CAISO control area comprises three large investor-owned utilities (Pacific Gas and Electric Company (PG&E) in Northern and Central California, and Southern California Edison Company (SCE) and San Diego Gas and

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The author is with the California ISO, Folsom, CA 95630 USA (e-mail: jprice@caiso.com).

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Electric Company (SDG&E) in Southern California), plus smaller municipal utilities. The current market design divides the CAISO control area into three large congestion zones ("NP15" in Northern California, "SP15" in Southern California, and "ZP26" in a portion of Central California), which are separated by two internal constraints, Path 15 and Path 26. The market's congestion management occurs on Paths 15 and 26, and on interties, with out-of-sequence dispatch being used for congestion management within zones. The current design ignores transmission congestion within these large congestion zones until the real-time market, using a look-ahead period of 2 h or less. This often forces the CAISO's transmission grid operators to scramble to correct infeasible day-ahead schedules. Indeed, because market participants do not know other market participants' bids, there is no way they could manage their schedules to all fit within transmission limits. There are no financial consequences for submitting day-ahead schedules that violate generators' operating limitations, and the CAISO must accept these operationally infeasible schedules. Existing market rules require each Scheduling Coordinator to anticipate customer demand and to match it with equal supply. This can create inefficiencies because there is no systematic way to ensure selection of the least cost supply to meet customers' needs. The CAISO currently decides which resources to use for ancillary services separately from its energy dispatch. Financial transmission rights are limited to rights to transmission service between adjacent zones and across interties. Currently, however, most congestion occurs inside the existing zones and there is no way for customers to protect against the "uplift" payments that recover these costs, which can be highly volatile and unpredictable, and which force some customers to subsidize the cost of serving other customers.

The impact of the current market design on the allocation of market costs is apparent from comparing inter-zonal congestion costs (between zones, charged to schedules that cross zonal boundaries) and intra-zonal congestion costs (within zones, recovered as uplifts regardless of cost causation). There are a variety of potential market designs (e.g., pricing as a single zone, pricing as multiple zones, or locational pricing). The designers of California's original market realized that enough congestion exists that a single zone would be inadequate for attributing costs correctly among market participants. The existing zones were established on a belief that intra-zonal costs would be infrequent and small. Instead, compared to inter-zonal congestion costs of $54.6 million in 2005 and $56 million in 2006, real-time intra-zonal congestion costs totaled $426 million in 2004, $222 million in 2005, and $207 million in 2006 [3]. Thus, the current zonal design fails to allocate congestion costs based on cost causation and affects reliability by delaying corrective action.

MRTU addresses these flaws through a number of system improvements to increase operational efficiency and enhance reliability. One fundamental feature is the Full Network Model (FNM) to represent the physical transmission topology and associated transmission constraints in the CAISO control area, and control areas that are embedded within or adjacent to the CAISO control area. Another foundation is the recently implemented state estimator. This component of the Energy Management System (EMS) system provides the CAISO with a near real-time assessment of system conditions, including portions where direct measurements of real-time conditions are unavailable. The FNM and state estimator allow the real-time market to start its dispatch from the current system status, and allows the day-ahead market to base its inputs on stored state estimator solutions. Alternating current (AC) network analysis supports the security constrained unit commitment (SCUC), to ensure that interactions between real and reactive power flows are considered. Thus, SCUC minimizes bid costs while respecting the physical characteristics of selected resources and transmission constraints, considering the marginal effect of losses due to injections at each location in the grid.

Integrating the FNM, SCUC, and the state estimator will allow the market optimization to ensure the feasibility of day-ahead as well as real-time schedules, and promote consistency between day-ahead schedules and real-time energy flows. Among the alternative approaches to market operations using a FNM are locational pricing, managing flowgates, and zonal pricing after determining feasible operating ranges for supply resources. The method implemented in MRTU is locational marginal pricing (LMP), whose principles are described in [4]. LMP directly and transparently calculates the actual cost of serving consumers at each transmission "node," including the costs of producing energy, congestion (i.e., the effects of transmission bottlenecks), and losses (i.e., energy lost as it travels over the wires). The CAISO will produce LMPs at 3000 or more locations in the CAISO, which will be paid to generation and other dispatchable resources. For nondispatchable load, the CAISO will calculate a load-weighted average price for each of three major utility service territories.

Although LMP is widely used in wholesale electricity spot markets, several concerns need to be addressed with respect to its application in California. One is the potential for high LMPs due to congestion in constrained areas. MRTU includes local market power mitigation that 1) pre-determines network constraints as "competitive" or "noncompetitive," 2) uses separate market runs to identify generators whose output is incremented with all constraints enforced, relative to their output with only "competitive" constraints enforced, and 3) mitigates these generators' bids to a pre-determined reference price if the bids exceed the reference price.

Nevertheless, variation will still occur in congestion costs. Market participants can use appropriate financial arrangements, including congestion revenue rights (CRRs), to protect or "hedge" themselves from high priced locations. CRRs will be awarded through an allocation process for Load Serving Entities, followed by an auction process for all market participants. However, today's zonal design provides no clear insight into the prices that will result under LMP, and market participants could be generally uncertain as to just how high LMPs may go and what their spatial and temporal pattern might be. To provide such insights, and generally shed light on the effectiveness of the MRTU design, the CAISO is conducting in-depth analyses of prices that would result if a LMP market were in place today, in [5].

Whereas the CAISO study's purpose is to establish a history of simulated prices that is useful in planning and implementing the market redesign, observations have also emerged about how operations compare between zonal and LMP markets. These observations are the focus of this paper, and are discussed after a summary of the study methodology.

III. LMP Study Methodology

A. Overview

The CAISO's LMP Study simulations utilize actual market bids and schedules from the CAISO's current "zonal" market design to estimate locational marginal prices. The simulations address the question, "What would market prices have been if all of the transmission constraints were enforced and transmission losses were considered in the optimal dispatch of generation plants?" This analysis is able to compute LMPs using historical market bids by using software that performs functions similar to the optimization that will occur in the MRTU systems.

The analysis requires a simulation approach because the actual optimization software to be used for calculating LMPs in a production mode is still in development and testing phases, and thus not yet available for this study. Multiple analytical steps are necessary to simulate MRTU's use of a forward and real-time congestion management procedure, using available software. As will occur in the actual market software, multiple systems are sources of inputs, including hourly load forecasts, outage reports, updates of transmission limits, and submitted market bids, in addition to preparation of the network model. For purposes of this simulation study, which has analyzed historical time periods, these data are obtained from the CAISO's data archives. One difference between the MRTU design and this simulation study is that the study can only model a single market timeframe (the real-time market), since the CAISO currently operates only a single energy market (in real-time) for which energy bids are available. The available desktop software does not offer optimized unit commitment and ancillary service reservations together with AC Optimal Power Flow (OPF) model for LMP pricing results. Thus, these tasks must use different analytical steps, which can be seen as analogous to the scheduling and pricing runs of the MRTU design. The hourly input data and the network models are direct inputs to both the unit commitment and AC OPF dispatch steps, and the outputs of unit commitment and ancillary service reservations become inputs to the final LMP calculation. The flow among these tasks is shown in Fig. 1, and discussed in subsections below.

This simulation approach models system dispatch for each hour of the year. Examining an extended period of market operations provides assurance that a wide range of operating conditions has been considered, and ensures that the variation of LMPs under significantly different system conditions has been represented. So that unusual events can be examined, detailed analyses are provided for specific case studies.

B. Input Data

Actual loads for the PG&E, SCE, and SDG&E transmission areas, and for several local areas within them (a total of 12 local areas), are calculated from telemetry data collected by the CAISO's EMS, to represent the real-time dispatch conditions. Calculated loads are reviewed and edited to correct anomalous data points. The results are converted to hourly nodal loads by scaling within each areas by multiplying the calculated load (net of losses) by the ratio of the nodal loads in the base case network model to the unadjusted area loads, essentially treating the network model's nodal loads as load distribution factors. Loads are price-responsive only if they actually submitted bids into the real-time market.

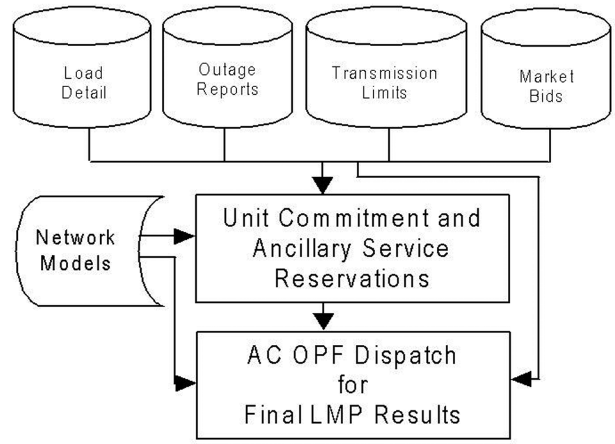

Fig. 1. Data flow for LMP study's simulation.

Actual generator outage data are reflected in the bid data through the bid validation process for the real-time market, which adjusts submitted bids for reported outages. Actual transmission outages are included in the FNM for major lines for each hourly interval, in the AC OPF dispatch step, through manual review of outage records for high voltage lines and transformers.

Actual hourly intertie limits, and limits for the two major internal branch groups that define the current congestion zones, are obtained from the CAISO's market data archive. Additional internal network ratings include the simultaneous flow limits and nomograms in the CAISO's operating procedures. Some of these constraints define import limits to areas within existing congestion zones, such as the Humboldt and North Bay areas, while others limit network flows but do not surround geographic areas, such as Miguel substation in San Diego, and simultaneous flow limits within the San Francisco Bay Area. Some limits vary with the occurrence of outages, but for purposes of this study, normal conditions have been assumed, to maintain feasibility in the input data preparation. The transmission interfaces include 34 interties to other control areas and 56 internal branch group and nomogram limits. In addition, limits for individual transmission lines, series capacitors, and transformers are enforced for 115 kV and higher voltage equipment.

The interties, Path 15, and Path 26 are enforced in the CAISO's real-time operations as both flow limits and scheduling limits. A flow limit requires that the flow across an affected path cannot exceed the specified capacity, while a scheduling limit requires that no more than the specified capacity can be scheduled from points that contribute to flow on the path. If unscheduled loop flow is in the same direction as the net flow from schedules on a path, the scheduled amounts must be reduced to keep the total flow within the specified capacity.

Where applicable, both types of limits have been enforced in the network model used in this study.

When MRTU is implemented, the state estimator will calculate unscheduled flow at each intertie. For this simulation, only a single value of unscheduled flow is available, at Malin substation on the California-Oregon border; a source or sink injection is therefore placed at Malin to model unscheduled flow, and this study assumes that the opposite source or sink injection is at Palo Verde substation in Arizona.

In addition to enforcing normal limits under each hour's conditions, the model includes "security constrained" economic dispatch (SCED), which applies additional limits based on the possibility that specific critical outages may occur. This "contingency analysis" re-runs the full power flow calculation using a series of assumptions that critical equipment is placed out of service. If violations of emergency transmission limits would occur, the software imposes limits on its dispatch to avoid or reduce the potential overload. The simulation's pricing run analyzes 104 $\mathrm{N}-1$ and critical $\mathrm{N}-2$ contingencies in the results reported herein (117 contingencies in the October 2004 simulation).

Transmission constraints are allowed to become "soft" at a marginal cost of $500/MWh for normal limits when telemetry confirms that the actual flow on the affected line, transformer, or simultaneous flow of multiple lines or transformers was over 85% of normal capacity during the hour that is being simulated, $200/MWh when telemetry did not confirm that the actual flow was near the normal capacity during the hour being simulated, and $100/MWh for contingency limits. These values are used here for study purposes based on observations that the applicable limits could not be readily maintained through generation dispatch, and that verification of the model results against telemetry of actual conditions revealed that under these conditions, overloads of normal limits have occurred at times, but did not necessarily result in shedding load.

The historical bid data available from the CAISO market includes both economic bids available for real-time dispatch and schedules that were established in the current day-ahead and hour-ahead markets. This simulation treats the previously established schedules as price-taker bids in real-time, at a bid price of $0/MWh. The available bids already include bid validation, outages, market power mitigation (which has rarely modified bids, in practice), and insertion of default bids as needed for must-offer resources. However, in order to model MRTU's change in the mechanism for reliability must-run (RMR) generation that is under contract for local reliability, bid modifications are necessary. RMR generation is currently dispatched before market bids are submitted, based on engineering studies. RMR generators then schedule the pre-dispatched output, and RMR generators are not dispatched in real-time below the pre-dispatched output. MRTU replaces the current methodology by determining the RMR requirement simultaneously with market power mitigation prior to the market optimization. The mitigated RMR generators' bids are then eligible to set market-clearing LMPs. To show the impact of local transmission constraints on LMPs, the model used in this study attempts to replicate the MRTU approach by extending or replacing the submitted energy bid curves for RMR generators, below the point of the RMR dispatch using a cost-based price. If the RMR generator had submitted a bid price below its cost-based level, the lower bid is used. This allows the RMR generators to be scheduled below their actual RMR dispatch points.

C. *Unit Commitment and Ancillary Service Reservations*

Optimized unit commitment and the co-optimization of energy dispatch and ancillary service reservations are key features of the MRTU design. The optimized unit commitment and ancillary service reservations in this study use the PLEXOS power market simulation software [6], which enforces constraints such as minimum run times and minimum down times, as well as accurately optimizing start-up and minimum load costs versus energy production costs, using Mixed Integer Programming (MIP). The MRTU production systems will also use MIP for these purposes. PLEXOS has a variety of features for purposes including market modeling, planning, and portfolio optimization. Specific studies would generally use a subset of features, such as this study's use of unit commitment, co-optimization, and scheduling using DC OPF. The PLEXOS implementation of MIP as used in this study uses a branch-and-bound approach to effectively find feasible solutions.

This study's basic formulation of co-optimization in PLEXOS is similar to MRTU (bid cost minimization for the combined services, subject to several types of constraints including but not limited to network limits, ramping limits, and regional minimum procurement of ancillary services in hours when the CAISO used regional procurement). The PLEXOS results for unit commitment become inputs for the "pricing run" step of this simulation study.

The processing time for a MIP optimization for unit commitment is affected by factors including the number of dispatch intervals over which the unit commitment is optimized and the size of the network model. This study uses PLEXOS with 24 1-h dispatch intervals in each period over which unit commitment is optimized, starting at midnight. This is the same as the day-ahead optimization period in MRTU. To maintain rapid execution times, this study has used a 385-bus equivalent network model in PLEXOS. With a total of over 700 generators, of which a) 200 submit economic bid curves for energy and the rest submit fixed schedules, b) 150 submit bids for ancillary service capacity, and c) 115 have minimum load levels substantially greater than zero and thus are subject to unit commitment decisions, the solution time using PLEXOS version 4.742 on a 1.7 GHz dual-processor PC is 3 h 40 min for a 31-day month. The model execution times are small compared to the time required for input data preparation and analysis of the model results.

D. *Pricing Run*

In the market processes that are being implemented for the MRTU markets, both the forward and real-time markets consist of separate processes that determine unit commitment and then final LMP prices. For example, in the MRTU real-time market, a pre-dispatch process will run every 15 min to determine unit commitment decisions, and is followed by an economic dispatch process that will run every 5 min to determine final dispatch targets and LMPs. Just as MRTU's real-time market has separate processes for SCUC and SCED, this study calculates final LMPs in a separate step, by using the "Security Constrained Optimal Power Flow" (SCOPE) AC OPF software [7] and a full 3800 bus network model of the CAISO system. This two-step process is necessary because SCOPE does not perform optimized unit commitment or co-optimization of energy and ancillary services, while PLEXOS uses a Direct Current (DC) OPF to perform these tasks.

The total LMPs are decomposed into energy, congestion, and loss components. While the specific calculation is done internally within SCOPE, the overall concepts are described in [8]. The CAISO has anticipated that it will use a distributed load slack variable rather than a single slack bus in its AC market dispatch optimization, and this study's AC OPF uses the same approach. Since a distributed load slack formulation for LMP decomposition distributes the system slack MW among the loads in proportion to their MW values, the reference energy price is similar to a load-weighted system average of total LMPs, and the loss and congestion LMP components are measured relative to the distributed load reference. In an AC power flow model, the alternative of using a single slack bus as the basis of LMP decomposition would mean that adjustments to balance supply and demand occur at a single bus. Marginal losses at other locations would depend on the choice of the single reference bus, which would affect the differences among the loss and congestion components of LMP at different buses. As demonstrated in [9], although the total LMPs do not vary with the choice of reference bus, the variation in the marginal loss factor impacts the marginal loss and congestion LMP components. This variation would affect financial settlements for these costs. In contrast, a distributed reference for LMP decomposition achieves values that are independent of the single reference bus [10]. Although changes in load distribution factors can still impact market results, using a distributed slack bus means that the market results are determined as a market design principle and not as an operational decision to choose one specific node instead of other alternatives.

E. Modeling Limitations

Any modeling effort unavoidably has limitations and relies on extensive assumptions. It is important to recognize that this study is not a forecast of LMPs under future market conditions. The model results may vary from actual operations for several reasons: the model assumes that all schedules and bids offered in the current market are within operating capabilities, that generators operate in perfect compliance with their schedules and dispatch instructions, and that the historical market bids would remain valid under the new market design.

Some limitations in the CAISO's current ability to replicate the MRTU design exist because supporting systems such as enhanced outage reporting are still being developed. This study has compared the model results to actual conditions, and concluded that despite these limitations, the model has been successful in demonstrating how the change in market structure would have affected the market results.

IV. Case Study Results

This study's modeling of each hour for more than 30 months of operations ensures that LMP variations under significantly different system conditions have been represented, but produces a volume of output data that precludes presentation of every hour's results. Examining case studies representing a variety of operating conditions provides a detailed picture of how the model results compare to specific market events, thereby demonstrating the validity of the results. This paper presents two case studies, followed by highlights of aggregated results.

A. Case Study: May 3, 2004

The first case study examines conditions on May 3, 2004, when unseasonably high temperatures in Southern California resulted in flows on a critical transmission corridor into Southern California's urban areas, known as "South of Lugo." The South of Lugo corridor brings power from the High Desert area northeast of the Los Angeles area into the eastern side of the greater Los Angeles metropolitan area, where other lines continue on toward the Southern California coastal plain. Temperatures reached 100°F in downtown Los Angeles, where temperatures are usually moderated by a coastal climate, compared to cities farther inland. The system-wide peak load reached 40 480 MW, a level typically not reached until peak days in midsummer. While new generation has been sited in California, Mexico, and the Southwest, there was insufficient transmission available to transport that generation to the load, especially in the greater Los Angeles area.

Due to these conditions the South of Lugo transmission lines overloaded between 3:00 and 6:00 p.m., requiring CAISO operators to redispatch the system in real time. As a result, real-time incremental dispatch volume reached 1800 MW, and the zonal market price of incremental balancing energy spiked to \$185/MWh. When flows exceeded the rating of the South of Lugo corridor, the CAISO declared a Transmission Emergency, which enabled the curtailment of nonfirm loads for mitigation of the high flow. The CAISO's operating logs report out-of-sequence (not in merit order) dispatches due to high loading at a major substation near the coast, and on the Southern California Import Transmission (SCIT) regional limit for total imports into Southern California, as well as on South of Lugo. The actual real-time zonal price for the SP15 congestion zone exceeded \$150/MWh for 3 h, and the average of this study's simulated LMPs in the SCE region exceeded \$200/MWh for 4 h; 36% of the simulated LMP prices in the month of May 2004 that exceeded \$100/MWh occurred on this single day, and another 60% of the prices exceeding \$100 occurred later in this week.

This impact of congestion is shown in Fig. 2, in which a zonal congestion price has been derived based on characteristics of the LMP decomposition relative to the distributed load reference that is used in this study's LMP simulation. That is, when LMPs are decomposed using the distributed load reference, the energy reference price is essentially equal to the load-weighted average of the total LMP, across the system, and the load-weighted average of the congestion and loss components is essentially zero. To create an analogy to decomposed LMPs using the current zonal prices, a load-weighted average of the zonal prices has been calculated for each hour to create an energy reference

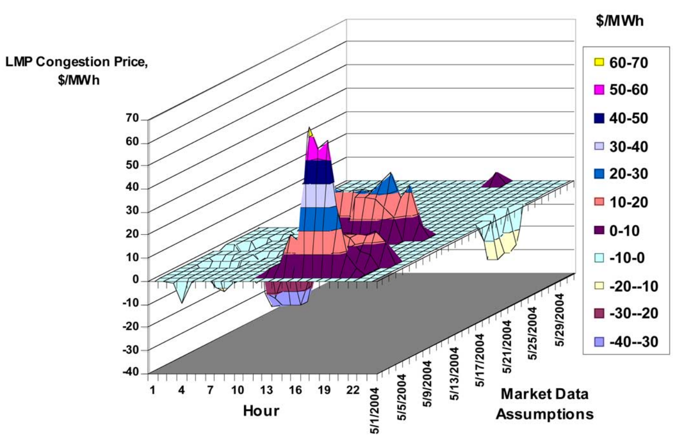

Fig. 2. Actual SP15 zonal congestion price for May 3, 2004 case study.

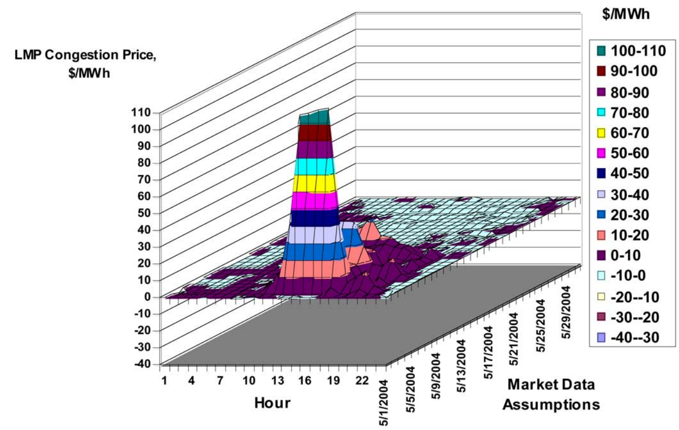

Fig. 3. Simulated LMP congestion price for SCE load aggregation in May 3, 2004 case study.

price, and each zone's "congestion" price equals its total zonal price minus the energy reference price. While it may appear that this calculation of the zonal "congestion" price is overlooking the loss component of LMP, in fact the loss component is not included in the CAISO's current zonal energy price. Instead, losses are settled using Generation Meter Multipliers that adjust the metered MW output of generation before paying the zonal energy price.

In Fig. 2, congestion costs are near zero in most hours, so the graph has a relatively large plane (i.e., a flat surface) at a congestion price of \$0/MWh, and positive congestion costs rise above the plane while negative congestion costs fall below it. The sides of the plane are defined by hour of day (Hour 1 to Hour 24), and by date (May 1 to May 31). Although the appearance in Fig. 2 is that the zonal congestion price for the "SP15" zone peaked at \$63.91/MWh in Hour 16 on May 3, 2004, the total congestion cost to the market was significantly higher. While the actual South of Lugo flow was at or above its rated capacity from Hours 13 to 18, the CAISO's operators began manually mitigating the high loading on lines in Southern California in Hour 10, and continuing manual mitigation through Hour 22. The mechanism for manual mitigation of congestion, when the zonal market mechanism does not provide bids in zonal merit order that are effective in controlling congestion, is out-of-sequence dispatch. Out-of-sequence dispatch costs do not appear in the zonal market clearing price and thus are not transparent to market participants, but are recovered from market participants nonetheless, in the form of uplift payments.

A goal of the CAISO in implementing MRTU is to increase market transparency, and minimize needs for out-of-sequence dispatch, by implementing system dispatch and pricing mechanisms that allow resources that are effective in relieving constraints to be included in the market price instead of in uplift payments. Fig. 3 shows the hourly congestion price for May 2004, with MRTU's LMP pricing in effect—that is, with the costs of all resources included in the market price instead of being hidden in uplift payments. While the peak congestion price in Fig. 3 is \$108.65/MWh in Hour 16, the CAISO's actual operating costs are no more than what were actually incurred on May 3, 2004. The difference in prices is a result of the increased

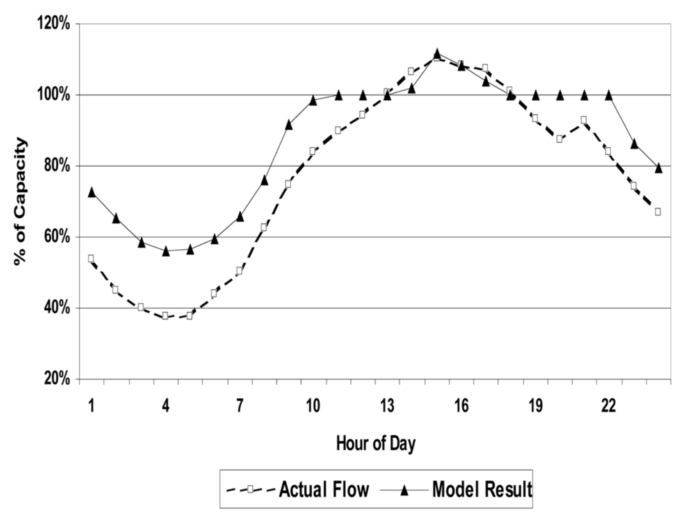

Fig. 4. South of Lugo flows in May 3, 2004, case study.

transparency of prices that show the value of energy throughout the grid, which in turn allows market participants to respond to the system conditions in ways they could not do when the costs were hidden in uplift payments.

Instead of incurring out-of-sequence costs through manual dispatch, the CAISO would be able to increase its transmission capacity utilization and reduce operating costs using the tools that MRTU is implementing, as shown in Fig. 4. Fig. 4 compares the actual flow on the South of Lugo corridor, obtained from the CAISO's telemetry data archives, with the flow using OPF dispatch. On May 3, South of Lugo is a binding constraint in Hours 11 to 22 of the model simulation, but as shown below, the OPF dispatch approach is able to maintain higher utilization of the South of Lugo capacity during this period than the CAISO's operators were able to do using more limited tools such as manual out-of-sequence dispatch.

During Hours 13 to 18, when the South of Lugo corridor's actual flow was at or above its capacity, and essentially all capacity had been dispatched that would be effective in reducing its flow, the modeled flow and the actual flow from telemetry are very close in value, which is a validation of the model results. (Flows on SCIT and other corridors near South of Lugo were high, but not at their limits.) Modeled flows on the SCIT corridor are also close to its capacity in Hours 14 to 17, but the model shows that the true binding constraint was South of Lugo, a result that is confirmed by the CAISO's telemetry archive data for this date. The CAISO's operators correctly observed high loading on other corridors, which they noted as the reasons for some out-of-sequence dispatch, and the generation that was dispatched would have been effective in relieving congestion on each of the heavily-loaded constraints. However, the OPF algorithm would have allowed the operators to accurately compare the effectiveness of different resources in determining cost-effective management of the constraints. Through multi-hour consideration of generators' operating characteristics, the SCUC process appears to be able to maintain higher utilization of the transmission capacity, and the tight integration that MRTU achieves between the EMS state estimator and market dispatch would allow the operators to closely monitor the capacity utilization as the software adjusts the dispatch as needed to stay within the rated capacity of the constraint.

A conclusion that can be drawn in these case study results is that the model results generally follow patterns that are consistent with prevailing system conditions. Extreme events (such as unusually high loads or the loss of major transmission lines) result in predictable changes in LMP price patterns. The location of congestion in the model has been similar to actual conditions that operators logged in the CAISO's operating records and executed corrective action. These findings are encouraging in that they suggest LMP pricing will, as it has in other markets, produce stable and predictable changes in LMP price patterns.

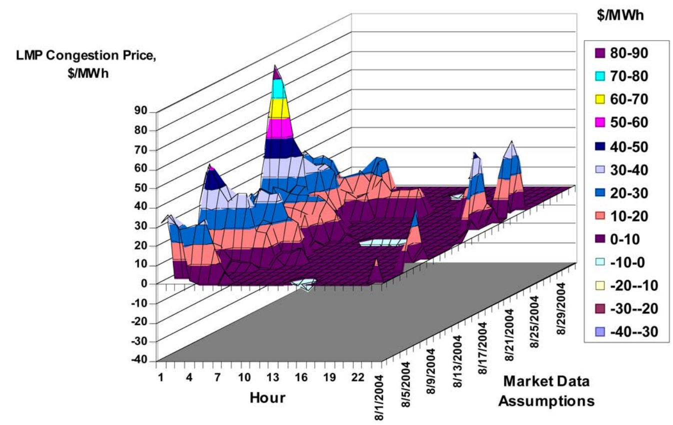

Fig. 5. Actual NP15 zonal congestion price in August 2004 case study.

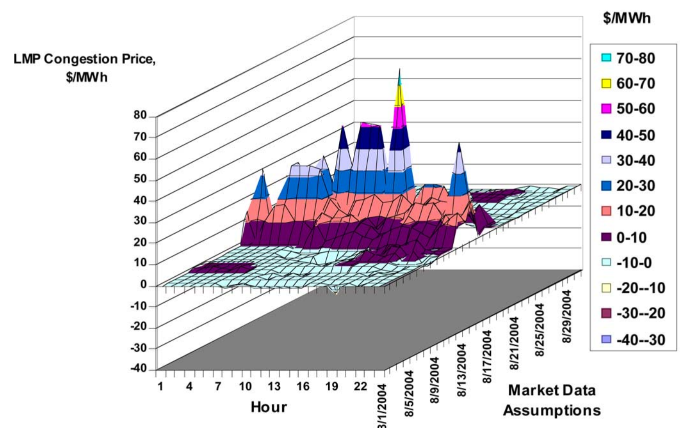

Fig. 6. Simulated LMP congestion price for PG&E load aggregation in August 2004 case study.

B. Case Study: MidAugust, 2004

Overall, the total number of hours of congestion in the Northern and Southern California are similar in the simulation and the actual zonal dispatch, but the magnitude of congestion within these areas may be less under the MRTU market structure because it provides better tools for market operations. However, results for August 2004 found significant differences between the specific hours of congestion between Northern and Southern California, comparing the actual historical market results under today's zonal market structure and the simulation results with the MRTU market structure. Significant amounts of nighttime congestion costs were experienced in actual operations, which OPF and the improved system management under MRTU would seek to reduce, but the LMP simulation showed large amounts of daytime congestion in mid-August. Detailed examination showed these to result from MRTU's operating tools revealing additional operating limits that were not recognized historically.

Fig. 5 shows the congestion in Northern California (in the current "NP15" congestion zone) in the current zonal market, using the same method of inferring a zonal congestion price as was in Fig. 2. Fig. 5 shows notable positive congestion costs during night-time hours, when thermal plants in Southern California and neighboring southwestern states must operate at "minimum load" output levels to remain available during the day, while hydropower output in Northern California and Pacific Northwestern states can be reduced to conserve their available energy for the peak hours. Fig. 6 shows the LMP simulation results for the same period. Although the total number of hours of congestion in Figs. 5 and 6 are roughly the same, two contrasts are readily apparent: night-time congestion in Fig. 5, versus daytime congestion in Fig. 6. The south-to-north nighttime flows in the LMP simulations remain lower than the rated capacity of Path 15. Instead, Fig. 6 shows a period of five days of notable daytime congestion.

The difference in nighttime congestion is also observed in other summer months, although in fewer hours. The reason why optimized dispatch under MRTU can eliminate much of this historical congestion is that operators previously needed to estimate flows in upcoming intervals, and set "bias" amounts for zonal dispatch or use out-of-sequence dispatch. They have had to do this while maintaining conservative operating margins, without having the state estimator and optimization tools that MRTU is implementing. The result is that during off-peak hours (10:00 p.m. to 6:00 a.m.) on August 15 and 16, actual Path 15 flows averaged 356 MW (13.4%) less than the real-time capacity rating. Fig. 7 compares the actual real-time path ratings and flows for these dates. If the available tools had allowed better reliance on optimized dispatch and closer coordination between

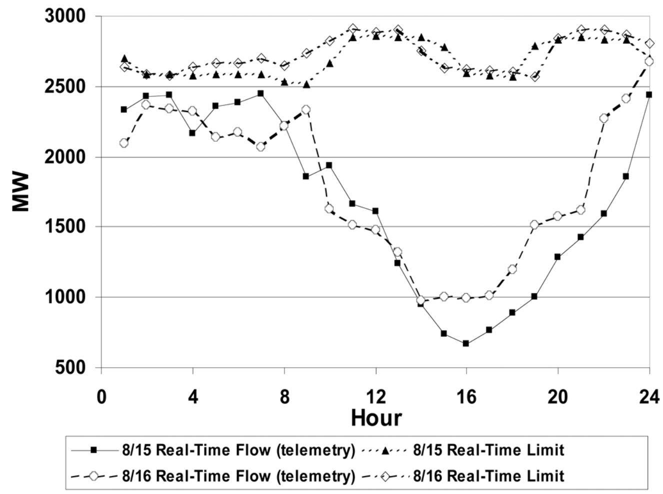

Fig. 7. Path 15 utilization, actual 8/15/04 and 8/16/04 data, in mid-August, 2004 case study.

the state estimator and market dispatch, much of the congestion could have been avoidable. As a result, the frequency and size of large departures during off-peak hours from the horizontal plane at $0/MWh in Fig. 6 (showing simulated LMPs) are much less than those in Fig. 5 (showing the effect of congestion on actual historical zonal prices).

Detailed result shows that the daytime congestion results stem from scheduled maintenance during construction of a third 500 kV line, as an upgrade to Path 15. Because of this construction, Path 15's rating was reduced by 1000 MW or more for operation of the CAISO's markets, but contingency analysis shows that if a remaining 500 kV line in this path were to have an outage, parallel 230 and 115 kV lines would have been overloaded despite keeping scheduled flows within the reduced path rating. Thus, including contingency analysis in the market dispatch would have had the effect of enforcing an even lower branch group rating. The current zonal market systems do not include contingency analysis in determining system dispatch, whereas MRTU includes contingency analysis as a source of constraints in its market dispatch, in order to better comply with system reliability criteria. In this case study, including contingency analysis in the market dispatch decisions would have allowed the CAISO to recognize that a lower branch group rating needed to be enforced, for reasons of system reliability.

V. Aggregated Results

The case studies above focus on specific conditions that reveal how MRTU's tools and LMP pricing interact with market operations, and provide insights into how these tools can result in better utilization of transmission capacity while improving the reliability of grid operations. Additional case studies are presented in the CAISO's LMP Study reports [5]. However, these case studies are not typical conditions.

To assess concerns that LMP would create adverse impacts through extreme geographic variation in market prices, the CAISO's study examines trends over time. While LMPs vary between areas within the CAISO from hour to hour, depending on the location of congestion, the model simulations do not support concerns that using LMP will create sustained adverse impacts on market prices. This section summarizes the results, which are available in full in [5].

Despite California's geographic diversity (spanning urban areas, large agricultural regions, coastal areas, mountains, and deserts), and the occurrence of a number of network constraints, average LMPs over time differ by only limited amounts. Areas where concerns about adverse congestion impacts of LMP were focused, such as San Francisco and Humboldt (a coastal area at the extreme northern end of the CAISO control area), have average prices that do not differ significantly from nearby areas. During the study period, the average congestion price is generally higher in Southern California than in Northern California, due to the presence of network constraints that affect most of Southern California. Some of these have now received transmission upgrades. Certainly, there are hours in which these and other areas have higher LMPs due to congestion, but these conditions occur for a limited number of hours. An exception has been the SDG&E area. There, three large generating plants near Imperial Valley substation (east of San Diego) began commercial operation during Summer 2003. This was before transmission upgrades into the San Diego metropolitan area could be completed. Because both Imperial Valley and the San Diego metropolitan area are both in the same existing congestion zone, the resulting transmission congestion has required manual intervention by the CAISO's operators through out-of-sequence dispatch. From Summer 2003 through Fall 2004, this manual out-of-sequence dispatch occurred for more than 20 h on a number of days. When OPF dispatch and LMP pricing are applied in these circumstances, the result is an increased average LMP in the San Diego metropolitan area and a decreased average LMP at Imperial Valley. Starting in November 2004, transmission upgrades between Imperial Valley and San Diego have begun commercial operation, which has now made congestion rare between these points.

Areas such as San Francisco and Humboldt had been the source of concern for congestion impacts because generation is limited in these areas, relative to their load. The presence of generation under Reliability Must-Run contracts (for reasons including voltage support) ensures that generation is available at cost-based prices when it is needed, which is an additional limit on congestion impacts. Instead, what is notable is that the LMP component for losses is higher in these areas than in nearby areas.

Finally, combining the revenues from load, generation, and interties, over the six-month period of May to September 2004, the total congestion and loss revenues amount to $400.9 and $345.4 million, respectively. Even though the CAISO is a summer-peaking area, these amounts are similar. While congestion prices have times when they are more extreme than the loss LMP component, they are sporadic, whereas the lower hourly costs of losses are present in all hours.

VI. Conclusion

The CAISO's simulations of pricing under the MRTU market design are a unique opportunity to compare estimated LMPs if the redesign were in place during recent historical periods with actual conditions, as logged in operating records. Case studies of congested network conditions demonstrate that optimization using SCUC and SCED, when tightly coupled with the state estimator, has the potential to both a) improve the existing utilization of transmission capacity and b) enhance system reliability. The case studies show conditions in which better utilization of transmission capacity can reduce congestion costs, and integrating contingency analysis with market dispatch can keep flows within limits for reliable system operation. Comparing the simulation results to actual operating conditions validates the simulations. Thus, differences in LMPs are a result of increased transparency of prices that show the value of energy throughout the grid, which in turn allows market participants to respond to the system conditions in ways they could not do when the costs were hidden in uplift payments as in today's market. Pricing results of the model simulations do not support concerns that using LMP will create sustained adverse impacts on market prices.

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James E. Price received the B.S. degree from the California Institute of Technology, Pasadena, and the M.S. and Ph.D. degrees from Stanford University, Stanford, CA.

He is a Lead Engineering Specialist in the Market and Product Development Department of the California ISO, Folsom, CA.