



California ISO

Market Redesign and Technology Upgrade Locational Marginal Pricing (LMP) Study 3C

Analysis of Market-Based Price Differentials

Description of Methodology

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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 activities are critical elements of the CAISO's core function, i.e., provision of reliable transmission service on a non-discriminatory basis. The last several years of operation have demonstrated the severe shortcomings of the CAISO's original "zonal" approach to congestion management, and during recent years the resulting operational and cost impacts have become progressively higher as new generation has come on-line in areas of the transmission grid that are congested by excess generation. Before the CAISO's market redesign is implemented, the CAISO is conducting a series of analyses to review the likely outcomes of its implementation. LMP Study 3C is part of this series of analyses, with the purpose of 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 document describes the methodology that is being used in LMP Study 3C.

The centerpiece of the CAISO's proposed redesign, known as Market Redesign and Technology Upgrade (MRTU), is a congestion management approach that uses a detailed mathematical model of the transmission grid instead of the highly simplified model used in today's zonal approach. The new design will improve grid reliability and efficient utilization of California's electricity infrastructure (transmission and generation facilities) by producing more transparent price signals and ensuring that forward (day-ahead) schedules are fully consistent with the way electricity actually flows over the grid in real time. In this manner, MRTU addresses the flaws of today's zonal congestion management approach, which ignores potential bottlenecks in the transmission grid and does not require consistency between day-ahead schedules and real-time energy flows. The CAISO plans to complete MRTU's implementation by early 2007.

In addition to ensuring feasibility of day-ahead schedules and promoting consistency between day-ahead schedules and real-time energy flows, one important benefit of the MRTU design is that it will reveal the actual cost of serving consumers at each specific location or "node" on the transmission grid. It does this by calculating "Locational Marginal Prices" (LMPs) at each node, which reflect the cost of serving the next MW of load at each node (including the costs of both producing the energy and delivering it to the node), through models that recognize transmission constraints and are based on efficient economic dispatch. The delivery component includes both the cost of congestion (i.e., the effects of transmission bottlenecks) and the cost of losses (i.e., energy that is dissipated as it travels over the wires). Because of

these delivery costs, the price of energy will typically be different at each node.¹ This is expected to encourage generation and transmission siting at locations where they are most needed to relieve system congestion. Another consequence of the MRTU design is that the CAISO will operate a transparent, day-ahead energy market that is fully integrated with the LMP congestion management procedure. Under California's original electric restructuring plan, the day-ahead energy market was a function of the Power Exchange, a completely separate entity from the CAISO that ceased operation during the 2000-2001 electricity crisis. MRTU will therefore restore an important function that has been missing since 2001.

Locational marginal pricing is not a revolutionary or experimental concept. In fact, it has become the most widely used approach for scheduling and pricing non-discriminatory transmission access and operating wholesale electricity spot markets, based on its successful performance in various wholesale energy markets throughout the world, including several ISOs in the eastern US (i.e., PJM (Pennsylvania, New Jersey, Maryland), ISO New England, and the New York ISO). Nevertheless, although locational marginal pricing is widely viewed as the most efficient and reliable electricity market design, several concerns need to be addressed with respect to its application in California.

One concern is the potential for high LMPs in certain constrained areas of the grid, where the cost of delivering energy to consumers is increased due to frequent, severe congestion. Because today's zonal design provides no clear insight into the prices that will result under locational marginal pricing, market participants are generally uncertain as to just how high LMPs may go and what their spatial and temporal pattern might be. To the extent market participants can develop some good estimates of these potential patterns, they can make appropriate financial arrangements to protect or "hedge" themselves from high priced locations. The tools for hedging financial impacts of potential pricing patterns include Congestion Revenue Rights (CRRs), which will be awarded through an allocation process for Load Serving Entities and an auction process for all market participants. To provide insights into the effectiveness of such tools, the CAISO is conducting in-depth analyses of prices that would result if a LMP market were in place today.

Other concerns that are being addressed through additional analyses before LMP pricing is implemented in the CAISO's markets include the identification of locations where some suppliers may be uniquely situated to relieve transmission constraints and therefore have incentives to profit from the constraints through their strategic bidding (often referred to as Local Market Power), for which the CAISO's MRTU design includes mitigation.² The CAISO will conduct analyses that can be used to estimate the potential impacts of these concerns and to evaluate potential remedies. While these are important concerns and must be resolved, it is worth noting that the eastern ISOs faced the very same issues and were able to successfully overcome them in transitioning to LMP.

¹ LMP will produce prices at 3,000 or more locations in the CAISO, which will be paid to generation and other dispatchable resources that bid into the CAISO's markets. For non-dispatchable load, the CAISO will calculate a single price for each of three major utility service territories, which will be load-weighted averages of each area's LMPs.

² The LMP method of pricing does not create market power where it would not otherwise exist. If a market participant has market power because of transmission constraints, it can be exercised and would impose costs on consumers in either a zonal or LMP system, since congestion must be recognized and relieved in either market design. For instance, a generator in a load pocket will have market power with respect to incremental dispatches to clear intra-zonal congestion, regardless of whether it receives LMP prices or out-of-sequence dispatch payments, while one in a generation pocket will have market power with respect to decremental dispatch (as has occurred historically near Miguel substation in San Diego).

To provide insights into the potential level and pattern of LMPs, the CAISO has previously published results from studies that utilize actual market bids and schedules from the CAISO's current "zonal" market design to estimate locational marginal prices. In the CAISO's LMP Study 3A, the CAISO has published reports in July 2004 discussing conditions from November 2002 to October 2003, and in October 2005 discussing conditions from November 2003 to April 2004.³ LMP Study 3A has addressed the question, "What would prices have been if all of the transmission constraints were enforced and transmission losses were considered in the optimal dispatch of generation plants?"⁴ In addition, the CAISO published a report in August 2005 in LMP Study 3B, which reexamined the 12-month period of market conditions from November 2002 through October 2003, but used the CAISO's expected 2006 network conditions and adjusted generation and load data to 2006 conditions, to calculate LMPs at each node of the transmission grid, for each hour of that period using assumptions to represent future conditions.⁵ LMP Study 3C follows these reports from LMP Studies 3A and 3B, with analyses similar to LMP Study 3A but with improvements in the study's methodology. The similarities and differences between LMP Studies 3A and 3C are described herein. Periodic analyses of LMPs that would result from current market bids will continue until the implementation of the proposed LMP-based market design.⁶

Review of LMP Study 3A Methodology and Assumptions

LMP Study 3C builds on the methodology that the CAISO used in LMP Study 3A. The original LMP Study 3A report describes its methodology in further detail. **In short, LMP Studies 3A and 3C both use actual schedules and market bid data, the MRTU market structure, and the CAISO's full network model (in a bus-branch model format) in an Alternating Current (AC) Optimal Power Flow (OPF) simulation to estimate prices that may occur in the CAISO's current real-time market if it were based on LMPs instead of zonal prices.** This section reviews the modeling features that are common to LMP Studies 3A and 3C, and subsequent sections describe details of specific aspects of the methodology and identify differences between Studies 3A and 3C.

³ The CAISO's published report in LMP Study 3A examined the first full year of the CAISO's operations since the October 30, 2002, implementation of MRTU Phase 1A, and is available at <http://www.caiso.com/docs/2004/01/29/2004012910361428106.html>. LMP Study 3A's starting date was chosen because the structure of real-time energy bids changed when MRTU Phase 1A was implemented. Previously, separate incremental and decremental energy bids were provided for supplemental energy and for each ancillary service. Along with other market changes, Phase 1A implemented a single energy bid curve, which enables this study to use consistent energy bids over the entire range of minimum to maximum available capacity from each supply resource.

⁴ 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. However, the historical market operations have used congestion zones for forward scheduling, market dispatch, and financial settlement.

⁵ LMP Study 3B used expected 2006 network conditions by using the CAISO's Grid Planning Model that was developed for its 2004 Controlled Grid Study, with internal interface and nomogram constraints adjusted to expected 2006 values. It incorporates generation additions that are listed in the CAISO's Controlled Grid Study Plan, and removes expected retirements from service as also listed in the Controlled Grid Study Plan. Loads are scaled to the CAISO's 2006 forecast. The report in LMP Study 3B is available at <http://www.caiso.com/docs/2005/07/01/200507011120032841.html>.

⁶ LMP Study 4 will be a successor to LMP Study 3C once the MRTU production systems have completed testing and can be used in routine operations. LMP Study 4 will resemble LMP Study 3C, but will use the MRTU production systems.

The actual optimization software and the final network model to be used for calculating LMPs in a production mode at the CAISO are not yet available. Therefore, the analysis and results presented in this report utilize a simulation approach. In its MRTU Comprehensive Design, the CAISO has proposed a forward and real-time congestion management procedure that adjusts generation, load, import, and export schedules to clear congestion using an Optimal Power Flow algorithm (OPF) and a Full Network Model (FNM) that includes all buses and transmission constraints within the CAISO Control Area. These LMPs incorporate the total value of generation, transmission congestion, and losses at each node of the CAISO system. By simultaneously enforcing all branch flow and other transmission constraints, this approach ensures that the final schedules are feasible with respect to all transmission constraints as well as generator ramping and other performance constraints, and eliminates the current distinction between inter-zonal and intra-zonal congestion.⁷ Starting with LMP Study 3A, the CAISO has used an Alternating Current (AC) OPF model for LMP pricing results, because a Direct Current (DC) OPF does not consider losses or reactive power and voltage constraints, which will likely have an additional bearing on derivation of LMPs and their variability. The most critical components of the MRTU market design have been reflected in LMP Studies 3A and 3B through the use of the “Security Constrained Optimum Power Flow” (SCOPE) AC OPF software, by Nexant, Inc./ Power Computer Applications.⁸

The CAISO is using this simulation approach to model 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 in the simulation, and ensures that the variation of LMPs under significantly different system conditions has been represented, including extreme conditions that occur infrequently. So that unusual events as well as more typical conditions can be examined, detailed analyses are provided for specific days that are selected as case studies, which represent a variety of operating conditions and which are selected to examine how LMPs vary under significantly different system conditions. In the presentation of case studies, it is important to understand that these selected days are not intended to be representative of the entire study period. To the contrary, some represent extreme conditions that occur infrequently.

Some limitations in the CAISO’s current ability to replicate the MRTU design exist because supporting systems such as enhanced outage reporting and the state estimator are still being developed and refined.⁹ The study described herein is characterized by the following features and assumptions, using market data that is specific to each hour of the study period:

- A real-time energy and congestion management market with no market separation rule or balanced schedule requirement;
- A market that will run for every hour of the year;
- Bid curve data, using market bids that are available for dispatch under the CAISO’s current market design, for dispatch of the resources that participate in the CAISO’s real-time energy market;

⁷ At times, this report uses the term “intra-zonal” to refer to locations that are within the CAISO’s existing congestion zones. This usage is intended only to distinguish congestion that must be managed today using mechanisms such as out-of-sequence dispatch, from congestion that is currently managed using market mechanisms. Both types of congestion will be managed in the MRTU markets using the same, uniform set of dispatch procedures.

⁸ Additional information about SCOPE is available at <http://www.nexant.com/products/PCA/scope1.html>.

⁹ In addition to limitations that will affect LMP Study 3C as a whole, initial reports issued in Study 3C may have limitations that will be noted in each report.

- Final hour-ahead generation schedules for resources that do not participate in the real-time market, with a \$0/MWh bid being assumed below the hour-ahead schedule to represent a “price taker” bid in the event that these schedules require decremental adjustment for congestion management, but no additional capacity being assumed as an economic bid;
- Actual generator outage data, as reflected in the bid data that is currently available for dispatch in the real-time market;
- A network model that ensures that the effectiveness of dispatch within the CAISO control area accounts for the associated network flows;
- Actual transmission outages for major lines;
- Additional consideration of significant potential transmission and generation outages, through contingency analysis that adds constraints to the dispatch optimization if a modeled contingency would lead to an overload above emergency transmission ratings;
- Actual hourly load data, aggregated similarly to load zones that will be used for aggregated demand bidding for participation in the real-time market;¹⁰
- Actual hourly import limits from current market data, and internal network ratings including critical constraints that are implemented in the CAISO’s operating procedures (e.g., simultaneous flow limits and nomograms);
- A \$250 soft bid cap;
- An alternating current (AC) OPF algorithm for calculation of LMP prices; and
- A one-settlement system for the real-time market, which treats all bids and schedules as if they had been submitted into the single market rather than having been established through sequential markets.

Network Model

When the MRTU proposal is implemented, the CAISO proposes to utilize a Full Network Model (FNM) that includes a detailed network model for the CAISO control area. The FNM used for LMP Study 3C has been developed from the 2006 network model developed for the CAISO’s 2004 Controlled Grid

¹⁰ The load zones for which hourly loads were determined, and the local load zones that are used for presentation in this report, are smaller areas than the Load Aggregation Points (LAPs) that are used for scheduling “non-participating” load (i.e., load that does not submit bids for participation in the real-time market). The CAISO’s MRTU design allows “participating” loads (i.e., loads that submit bids for optimized scheduling and dispatch in the CAISO’s energy market) to be aggregated for bidding purposes with some restrictions such as size and geographic proximity relative to significant transmission constraints, and with exceptions such as allowing aggregation of water delivery systems that are distributed among more than one of the local load zones that are used in this report; settlements will consider the nodal distribution of the participating load. The areas where aggregation of participating loads will be allowed have not been finalized at this time, and the local load zones used in this report are an approximation pending further study.

Study,¹¹ which is a “bus/ branch” structure that includes all transmission lines and transformers in the CAISO Control Area but omits added detail of breakers within substations. This network model is the same that was used in LMP Study 3B, with adaptation to each study period within LMP Study 3C by removing future upgrades from service if they will become operational after that study period. Generators are added so that all resources that participated in the CAISO’s markets during each study period are represented in the market model. (If a generator has not bid or scheduled in a particular hour, the dispatch simulation causes the generator to be de-committed.)

The CAISO will initially use a network model that extends only to its external scheduling points, but not between the external scheduling points due to issues of coordination among markets affecting different control areas. However, the CAISO is considering eventually using a simplified equivalent network for areas outside the CAISO Control Area, including external loops, for the real-time market and possibly the forward markets if the interactions among control areas can be adequately represented. If these interactions can be represented, the real-time market instructions and price signals would be able to reflect, as closely as possible, the real-time grid operational needs and standard operating actions taken by the CAISO operators, and avoid a divergence between grid operational instructions and real-time market solutions. LMP Study 3A incorporated the external loops beyond the scheduling points into the CAISO grid, using a 600-bus electrical equivalent network model outside the CAISO Control Area, to allow the

¹¹ The original 2006 network model used in the CAISO’s 2004 Controlled Grid Study can be downloaded from the WECC web site, <http://www.wecc.biz>. The network model is described in the Controlled Grid Study Plan, which is available at <http://www2.caiso.com/docs/2004/08/23/2004082314301729916.pdf>. The following adjustments to the Controlled Grid Study model have been made due to the modeling needs of an AC OPF simulation using SCOPE, in LMP Studies 3B and 3C:

- Generators have been added so that all generators that participate in the CAISO’s markets are represented in the model.
- To form the starting case to which market data is added to produce the hourly input files that are used in the OPF simulation, all generators have initially been set to an “in service” status, and the hourly OPF simulations then de-commit generators as determined by their schedules and bids.
- To create the “open loop” network model, network components beyond the intertie scheduling points have been deleted from the model.
- Due to limitations in modeling of DC lines (which are radial connections to intertie scheduling points, in the “open loop” network model), the Pacific DC lines and Intermountain DC lines have been replaced with AC equivalents.
- For branches whose resistance is negative in the original network model, the resistance has been replaced with zero.
- Because Metered Sub-System (MSS) operators are responsible for losses and congestion within their MSS, branch resistances with MSS areas have been set to zero, and branch ratings have not been enforced.
- Conflicting transformer tap settings of parallel transformer banks have been set to consistent values.
- Phase shifter adjustment ranges have been expanded to accommodate the full intertie capacity at their location.
- Control ranges for voltage-regulating generators and shunts have been made consistent within local areas of the network by having generators and shunts control the voltage at a common bus, with the controlled buses and voltage control ranges being refined during LMP Study 3C after analysis of previous LMP Study results.
- Ten branch ratings have been replaced with values from the CAISO’s Transmission Registry and CAISO Operating procedures.
- Ratings for a small number of branches where reactive (MVar) power flows cause MVA limits to be binding constraints but cannot be validated against telemetry measurements of actual flows, the branch ratings are enforced as MW limits rather than MVA limits.

CAISO to analyze the impact of the LMP market as it will be ultimately implemented. However, since the CAISO will initially use an open-loop model when MRTU is implemented, LMP Studies 3B and 3C use an open-loop model. The CAISO believes that this report's major results are not affected by whether a closed or open loop model has been used, but the impact of using a closed loop model will be examined in further detail at a later date as the CAISO prepares to implement a closed loop model.

Because external areas outside the CAISO Control Area are not modeled, hourly telemetered values of unscheduled flow at Malin are modeled using source and sink injections that are assumed to be at Malin and Palo Verde. Transmission interface limits (also known as "branch groups" or "flowgates"), individual transmission lines, series capacitors, and transformers are dynamically defined and selectively enforced in the optimization. For this analysis, transfer limits for Path 15, Path 26, and other transmission interfaces within the CAISO Control Area are enforced, as are essentially all transmission lines and transformers at 115 kV and above.¹² Interface limits that are obtained from the CAISO's market database limit flows in the transmission grid to specified limits that may vary hourly.

There is no distinction between inter-zonal and intra-zonal transmission limits, and all congestion is cleared simultaneously in one step. In addition to transmission interfaces that currently separate the CAISO's existing congestion zones, a number of additional constraints are included in this study. Some transmission interfaces define import limits to areas within existing congestion zones, such as the San Francisco, Fresno, and North Bay areas, while others limit network flows but do not surround geographic areas, such as Miguel substation in San Diego, Vincent substation, and simultaneous flow limits within the Bay Area. Some limits vary with the occurrence of outages, but for purposes of this report, normal conditions have been assumed.¹³ In addition to essentially all individual branch constraints at 115 kV and higher voltages, the transmission interfaces used in this report include:

Current Branch Groups:¹⁴

- a) Branch groups that are currently used in the CAISO's markets, including Path 15, Path 26, and the interties to other control areas,

Area Import Limits:¹⁵

- b) Fresno generation nomogram (3 segments),
- c) Humboldt import limit,
- d) North Geysers area import limit,
- e) San Francisco import nomogram (North of Martin),¹⁶

¹² In an ideal implementation of the LMP approach, all important network elements and their limits would be individually represented in an AC load-flow model, in order to detect and manage all constraints for which the CAISO is responsible. In practice, however, this may not be feasible, because the development of the network model is an ongoing project.

¹³ Current limitations in data available from the CAISO's outage tracking system have limited the extent to which network constraints could be automatically updated in this study to reflect outages.

¹⁴ Hourly Operating Transfer Capability (OTC) limits are modeled on each interface for which the limits are in the CAISO's market databases. Because this study models the real-time market, unused ETC reservations are available to the market and are not subtracted from the OTC limits that are obtained from the CAISO's market databases.

¹⁵ LMP Study 3A used area import limits that were defined during the Comprehensive Market Redesign (CMR) project in 2000. For LMP Study 3C, limits defined in the CMR project have been replaced in this study by limits obtained from CAISO Operating Procedures.

¹⁶ Effective through August 2005.

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- f) San Francisco interfaces (Martin – Bayshore/ Potrero, Martin – Hunters Point),¹⁷
- g) SDG&E and CFE combined imports,
- h) SDG&E import flow limit,
- i) SDG&E import limit as % of load (minimum SDG&E area generation),
- j) SCE import limit as % of load (minimum SCE area generation),

Regional Import Limits:

- k) Southern California Import Transmission (SCIT),¹⁸

Pacific Gas and Electric Area (PG&E):

- l) Pittsburg to San Mateo + Pittsburg to East Shore,
- m) Ravenswood 230 kV,¹⁹
- n) Tracy to Tesla,²⁰
- o) Contra Costa 230 kV imports,
- p) Tesla to Pittsburg,
- q) Tesla – Delta Switchyard,²¹
- r) Tesla – Bellota Cutplane,
- s) Tesla bank,²²
- t) Moss Landing to Metcalf,
- u) Oakland 115 kV,
- v) Moraga/ San Leandro – Oakland,
- w) Sobrante 115 kV,
- x) Metcalf – El Patio,
- y) Pittsburg bank,
- z) Metcalf – Morgan Hill/ Llagas,
- aa) Llagas – Gilroy,
- bb) Humboldt bank,
- cc) Keswick – Cascade,
- dd) Geysers 230 kV,
- ee) Sierra/ Drum area generation (3 limits),²³
- ff) Drum – Rio Oso,
- gg) Rio Oso – Drum,
- hh) Newcastle – Flint,
- ii) Palermo – Colgate,
- jj) Palermo 115 kV,

¹⁷ Effective starting September 2005.

¹⁸ For the Southern California Import Transfer (SCIT) nomogram, the limits have been set by (1) observing whether either the CAISO's daily operating report (or other records of operating logs) or an initial OPF model run (which uses an initially-assumed interface limit that is replaced before producing the final results) indicate that these limits may result in congestion, and then (2) in the hours when congestion is likely to occur, re-running the model with the flow limited to the actual allowable flow for the operating hour, determined from telemetry and a detailed calculation of the SCIT nomogram.

¹⁹ Effective through June 2005, after redefinition effective November 2004.

²⁰ Effective through June 2005.

²¹ Effective starting September 2004.

²² Effective through October 2004,

²³ Effective through March 2005.

- kk) Table Mt. – Rio Oso,
- ll) Bogue Area Import,
- mm) Bogue Area Export,²⁴
- nn) Colgate 60 kV,²⁵

San Diego Gas and Electric (SDG&E) Area:

- oo) North of SONGS (Path 43),
- pp) South of SONGS (Path 44),
- qq) Miguel Import,
- rr) Miguel nomogram,
- ss) El Centro bank,
- tt) Imperial Valley bank,
- uu) N. Gila – Imperial Valley,

Southern California Edison (SCE) Area:

- vv) South of Lugo,
- ww) Vincent bank,
- xx) South of Magunden,
- yy) Mira Loma bank, and
- zz) Serrano bank.

The interties, Path 15, and Path 26 are generally recognized as having 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 (between Malin and Palo Verde, as discussed above) 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. However, if unscheduled loop flow is in the opposite direction, it cannot be used as a counter-flow to schedule more than the specified capacity at a scheduling point. Where they are applicable, both types of limits have been enforced in the network model used in this study.

In addition to enforcing normal transmission limits under the conditions that occurred during each hour, the modeling for each hour has included “security constrained” dispatch, which applies additional limits based on the possibility that specific critical outages may occur. This process uses “contingency analysis”, in which the full power flow calculation is re-run by the OPF software using a series of assumptions that critical transmission equipment or major generators are placed out of service. If violations of emergency transmission limits would occur under the contingency conditions, the software imposes limits on its dispatch to avoid or reduce the potential overload.²⁶ LMP Study 3C analyzes more than 100 contingencies, in addition to the base case representing actual conditions, most of which are the physical facilities listed in Attachment 4 of the CAISO’s Controlled Grid Study Plan, used individually as N-1 contingencies. A small number of additional N-2 contingencies are also included, which are identified in CAISO operating procedures as the basis for nomograms or minimum generation requirements. In most cases, the contingencies that were used in this study test conditions after loss of a single transmission circuit or generator. In one case, the contingency definition reflects that the loss of a 500 kV to 230 kV

²⁴ Effective through Fall 2004.

²⁵ Effective starting April 2005,

²⁶ The software internally adds constraints to its optimization process to ensure that the dispatch will avoid or reduce potential overloads.

transformer would automatically trip two of the three 230 kV transmission lines that connect the substation to a major generation plant, thereby reducing the generator output; this contingency was modeled as outages of the transformer and the two 230 kV lines. In another case, loss of a 500 kV transmission line can overload two parallel 230 kV lines, which would trigger a reduction in output at a major generation plant; when this result occurs, this contingency was modeled as outages of the 500 kV line and some of the individual generation units at the plant.

Supply Bids

As noted above, the treatment of bid curve data was established in LMP Study 3A, using market bids that are available for dispatch under the CAISO's current market design, for dispatch of the resources that participate in the CAISO's real-time energy market. Final hour-ahead generation schedules for resources that do not participate in the real-time market are treated as "price taker" bids in the event that these schedules require decremental adjustment for congestion management, by assuming a \$0/MWh bid below the hour-ahead schedule, but no additional capacity is assumed to be available as an economic bid. Actual generator outage data is reflected in the bid data that is currently available for dispatch in the real-time market.

Initial reports in LMP Study 3C will continue to use the general framework for analyzing RMR generation that was established in LMP Study 3A. That is, in an effort to show the impact of local transmission constraints on LMPs, the model used in this study has extended the submitted energy bid curves, for generators that have received RMR dispatch instructions, below the point of the RMR dispatch using a cost-based price. In cases where the RMR dispatch occurred after the submission of energy bids for the real-time market, the bid curve is replaced with the cost-based bid below the RMR dispatch. If the RMR generator had submitted a bid price below its cost-based level, the lower bid is used. In LMP Study 3A, RMR generators that did not submit real-time energy bid curves were considered to be self-scheduled at the higher of their final hour-ahead schedules or their RMR dispatch, so a \$0 decremental bid price was used. However, the results were subject to uncertainty as to whether this modeling assumption masked some congestion costs; although re-running some periods when high congestion costs were present in the model results suggested that any effect of this type was limited, LMP Study 3C changes Study 3A's assumption by using a cost-based bid below the point of RMR dispatch even when the generator is self-scheduled. In the CAISO's current market operations, RMR generators are generally not dispatched in real-time below the RMR dispatch point, and decremental energy needs will be dispatched from lower-priced energy bids. However, in the MRTU market design, the CAISO's proposals have been to determine RMR dispatch for congestion management due to local transmission constraints from the market dispatch runs, with energy bids below the RMR dispatch point (i.e., the minimum MW output that the generator is directed to produce to manage congestion) being at cost-based prices; RMR dispatches for voltage and stability constraints will be pre-determined and not set by the market dispatch runs. That is, in the MRTU market, (1) the CAISO's operators can pre-designate minimum output levels for RMR generators in order to maintain reliability, before the market systems begin to process market participants' bids, then (2) the market systems determine needs for RMR generation due to local (i.e., non-competitive) transmission constraints and needs to mitigate non-RMR generators' bids due to local market power, through a series of market dispatch runs that result (among other things) in replacing some bid segments with cost-based bid prices, then (3) the CAISO's operators have an additional opportunity to review the resulting dispatch to

ensure that system reliability is maintained, and to alter the dispatch if needed, before (4) final runs of the market systems determine the final dispatch and prices. The modeling approach in this study of allowing the RMR generators to be scheduled below their actual RMR dispatch points, at a cost-based bid price (which replaces the energy bid segments of RMR generators, below the RMR dispatch point, and allows the RMR generators to be dispatched below their RMR dispatch, and to set market clearing LMPs), attempts to mimic the MRTU market design but alters the dispatch compared to today's operating practices.

The CAISO has continued to explore alternatives for improving the modeling of RMR generation as a source of local congestion management, and changes in the LMP Study 3C methodology are likely during its series of study periods. In addition, LMP Study 3C has not yet incorporated MRTU's Local Market Power Mitigation features. Revisions to the treatment of RMR generation in LMP Study 3C, as well as methods for modeling Local Market Power Mitigation, will be discussed in a future document.

In LMP Study 3A, the limits imposed by intertie schedules and flows have been maintained by scheduling final hour-ahead quantities at external scheduling points, and considering supplemental energy bids on interties for potential dispatch if (1) they were at least partially pre-dispatched before the actual operating hour, or (2) they were not submitted with a requirement to be pre-dispatched. In today's real-time market, supplemental energy bids on interties are not available for dispatch if they are submitted with a requirement to be pre-dispatched and such pre-dispatch does not occur; because the pre-dispatch decision can involve operator judgment concerning factors that are not available to this study's market simulation model, these bids are included only if they were at least partially pre-dispatched. This restriction is not applied in LMP Study 3C due to changes in the Automated Dispatch System (ADS) for MRTU Phase 1B.

Load Data

Actual loads for the PG&E, SCE, and SDG&E transmission areas, and for several local areas within them, are obtained from telemetry data collected by the CAISO's Energy Management System.²⁷ Because participating loads are represented as generation in the power flow model and in the model's dispatch, their hour-ahead schedules are removed from the total load and converted to energy bids; their loads then appear in the model as negative output from these "generators".²⁸ Loads for local areas within the major transmission areas are then subtracted from the major transmission area loads, to represent the load for the balance of the major areas. The resulting area loads are converted to hourly nodal loads by scaling the loads within each aggregated area, i.e., by multiplying the calculated load net of losses by the

²⁷ After the extraction of raw data from telemetry, calculated loads for each area are reviewed for anomalous data points. If forecasts of loads for the local areas are available, either from the CAISO's load forecasting systems or from calculations prepared for LMP Study 3C, the local area loads obtained from telemetry are accepted if they are sufficiently close to the forecasted load. If the local area loads obtained from telemetry are outside a tolerance band around the forecast, they are set to the edge of the tolerance band.

²⁸ The participating loads that exist in today's market should not be confused with loads that may be aggregated in the future within local load zones like those used in this report. The participating loads that are active at present are water pumps that are large enough to be represented in the network model.

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ratio of the nodal loads in the base case network model to the unadjusted zonal loads, essentially treating the network model's nodal loads as load distribution factors; nodal load estimates are not yet available from the CAISO's state estimator. For purposes of this study, load data (consisting of actual loads and uneconomic adjustment bids) are used for the following areas; the local load zones used for presenting the study's results are provided for comparison:

Load Aggregation Point (used in MRTU for Day-Ahead load scheduling)	Load Calculation Area (used as input data)	Local Load Zone (used for reporting purposes)
PG&E	San Francisco (North of San Mateo)	PGSF San Francisco
	Bay Area (except for San Francisco)	PGDA De Anza PGEB East Bay PGME Metcalf PGP2 Peninsula PGSB South Bay
	Humboldt	PGHB Humboldt
	North Coast (North Geysers 115 kV transmission system)	PGNC North Coast
	Geysers (South Geysers 230 kV transmission system)	PGFG Geysers
	Fresno	PGF1 Fresno
	Sierra	PGSI Sierra
	Los Padres (ZP26)	PGLP Los Padres
	Remainder of PG&E service area	PGBC Battle Creek PGCC Central Coast PGDE Delta PGNB North Bay PGNV North Valley PGSA Sacramento Valley PGSN San Joaquin PGST1 Stockton PGST2 Stockton PGVA Vaca-Dixon
SCE	L.A./ Orange County RMR area	SCES SCE Southwest ²⁹
	Remainder of SCE service area	SCES SCE Southwest SCEC SCE Core SCEN SCE North SCHD High Desert SCLD Low Desert
SDG&E	SDG&E service area	SDGE San Diego SDMIV Imperial Valley

Aggregated prices for these local load zones are calculated as load-weighted averages from the LMPs produced by the OPF model. These local load zones are aggregations of load points, as are the existing congestion zones, demand zones, and load groups. Among the purposes of these load zones in

²⁹ The LA/ Orange County RMR area is part of the SCE Southwest area that is used for reporting results.

the MRTU market design are to provide a means for reporting LMPs that are representative of LMPs in areas that are affected similarly by congestion in the transmission network, for example to facilitate the presentation in this report. The aggregated prices reported herein are used to maintain the volume of output data at a manageable level for tables and graphs, and do not alter the CAISO's position in the July 2003 Amended Comprehensive Market Design that most loads should be settled using prices that are aggregated at the Load Aggregation Point (LAP) level. (The level of aggregation reported herein does remain meaningful for facilitating demand response that participates as aggregated dispatchable resources in the CAISO's markets.) The preliminary load zones used here for reporting purposes may differ from the areas that will ultimately be used when LMP goes into production, and the final definition of load zones will not be established until further analysis of price dispersion has been completed.

Loads are set to actual load levels, to represent the conditions under which real-time dispatch would occur. Loads are treated as price-responsive only if they have actually submitted bids into the real-time market. However, aggregated load bids include an uneconomic adjustment bid as proposed in the CAISO's MRTU design. For purposes of this study, this is an implicit bid at \$1000/MWh to adjust load if necessary for congestion management and pricing, but not necessarily for operational purposes. This bid is intended to manage congestion while protecting load from severe impacts of locational marginal pricing.³⁰ In practice, no adjustments of loads have occurred in LMP Study 3 results to date due to the uneconomic adjustment bid. In addition, 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 at least 90% 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.

Unit Commitment and Ancillary Service Reservations

LMP Study 3A was subject to a limitation of assumptions of hourly dispatch with no constraints on hours of continuous operation or optimization of unit commitment between hours. Unit commitment and ancillary service reservations could only be approximated in LMP Study 3A, whereas optimized unit commitment and the co-optimization of energy dispatch and ancillary service reservations are key features

³⁰ The result of including uneconomic adjustment bids is to maintain scheduling priorities among various types of schedules in the event that economic bids are insufficient to relieve congestion. This mechanism does not pretend that the load does not exist, but instead reflects operational concerns: (a) in real time, the CAISO's operators will dispatch resources to the extent possible, and may be able to use emergency transmission ratings, to maintain service to firm load, and (b) in forward markets, the residual unit commitment process will seek to ensure that adequate resources are available in real time regardless of whether or not load has been scheduled through market bids or affected by the uneconomic adjustment bid. Note that in the modeling results in this study, the uneconomic adjustment bids on load schedules have not been necessary for relieving congestion. However, transmission constraints have become "soft" in a limited number of instances.

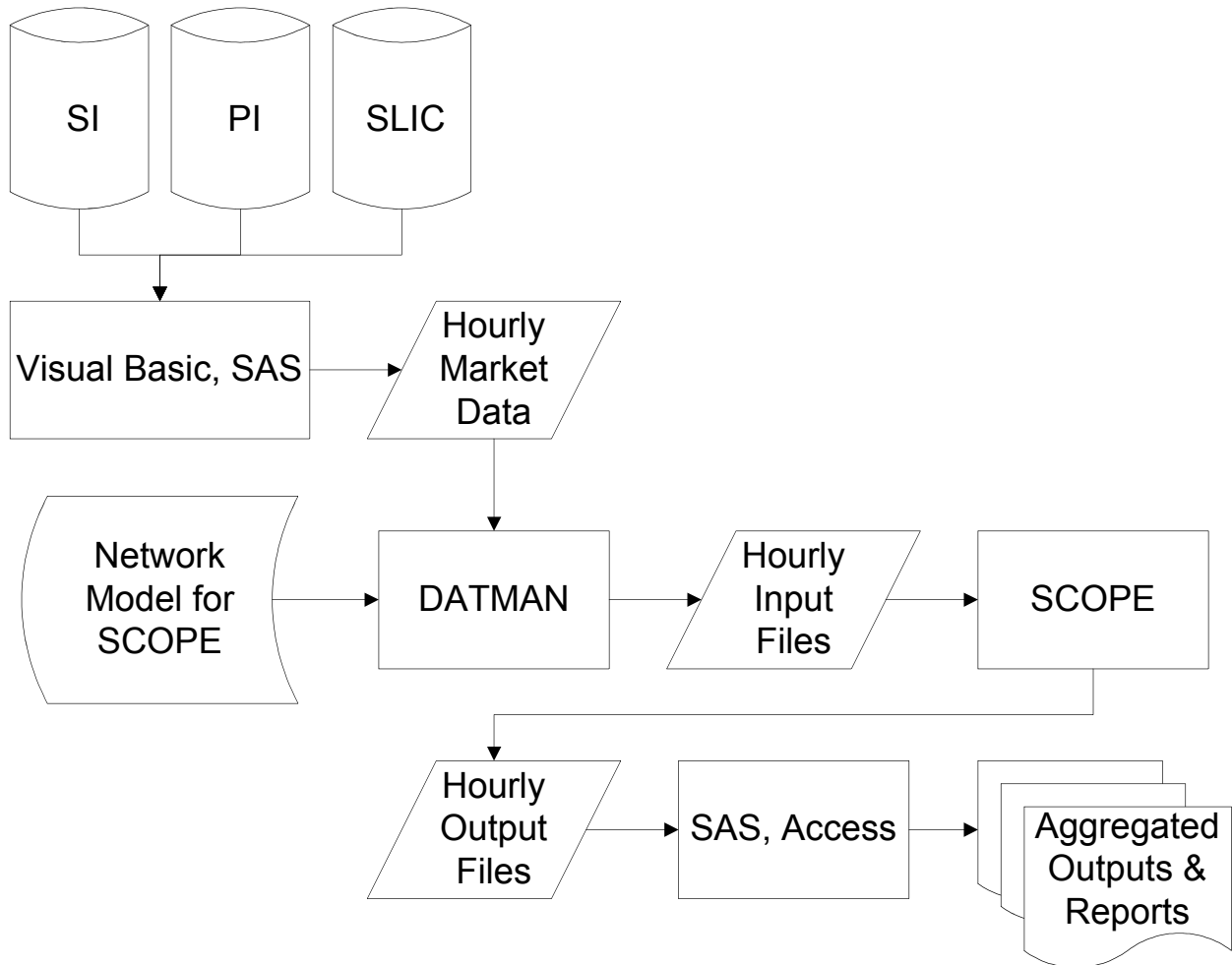
of the MRTU design. In LMP Study 3C, the CAISO is significantly improving its modeling methodology in these areas.

In LMP Study 3A, unit commitment for each hourly case was approximated by (a) requiring generators with positive hour-ahead schedules to be committed, (b) instructing SCOPE to de-commit generators that do not have positive hour-ahead schedules and have not submitted bids in the real-time market, through inputs to SCOPE that coincide with these generators' bid data, (c) for generators with start-up times exceeding two hours, using a \$0/MWh energy bid from 0 MW to the higher of the minimum operating capacity or the lowest MW point contained in the generator's real-time energy bid, (d) for generators with start-up times exceeding two hours, instructing SCOPE to commit the generator if the LMP at its bus exceeds \$1/MWh, (e) for generators with start-up times under two hours, extending their submitted real-time energy bid curves downward to 0 MW, and (f) for generators with start-up times under two hours, instructing SCOPE to commit the generator if the LMP at its bus exceeds its lowest real-time energy bid price. In addition to the CAISO's construction of these assumptions, market participants have had some discretion over their unit commitment, and expressed their commitment decisions through their schedules and bids as submitted to the CAISO.

Ancillary service reservations were partially represented in LMP Study 3A using SCOPE's "reserve group" feature. SCOPE's "reserve group" constraint does not account for generators' ramping capability within 10 minutes, so the CAISO has used the "reserve group" constraint to ensure that the largest amount of reserves, i.e., total operating reserve, would remain as unloaded capacity among the set of generators that are providing spinning or non-spinning reserve or upward regulation.

A comparison of Figure 1 and Figure 2 illustrates LMP Study 3C's methodology for implementing improved unit commitment and ancillary service optimization. Figure 1 shows the process for hourly OPF simulations in LMP Study 3A. Input data relating to the CAISO's markets, such as branch group capacities and market participants' bids and schedules, are read from the CAISO's System Infrastructure (SI) databases using Visual Basic scripts. Input data involving telemetry data, such as the calculation of local area loads, are read from the CAISO's Plant Information (PI) archive. Input data involving outages are extracted from the Scheduling and Logging for the ISO of California (SLIC) database, manually reviewed for outage status and linking to the network model, and stored for merging with other data. Using Visual Basic and SAS scripts, these data are formatted as hourly files of market-related data for entry into DATMAN, which is a data management program that accompanies SCOPE as parts of PCA PowerSuite. In DATMAN, the hourly market data files are merged with a static network model that is the starting case for all hourly OPF simulations, which contains the network model and related data such as network constraints and nomogram definitions. The output of DATMAN is a series of hourly input files for OPF simulations using SCOPE. SCOPE produces a series of hourly output files containing the results of the OPF simulations, which are processed using SAS scripts and MS Access queries to produce aggregated output files for preparation of the final LMP Study reports.

Figure 1: Process Flow for LMP Study 3A



As shown in Figure 2, LMP Study 3C maintains the same general flow for the use of SCOPE, but adds a preceding process that estimates an optimized unit commitment and ancillary service reservations, by adding PLEXOS. PLEXOS is a power market simulator that is produced by Drayton Analytics (extensive information is available on-line at www.draytonanalytics.com) for electricity market modeling, planning, and portfolio optimization, which includes solution methods based on linear, mixed integer and quadratic optimization. Because Mixed Integer Programming (MIP) is necessary to fully represent an optimized unit commitment that 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, and because the MRTU production systems will use MIP for these purposes, LMP Study 3C uses the MIP solution method in PLEXOS.³¹ To incorporate PLEXOS into the overall process flow for LMP Study 3C,

³¹ The solution time for an optimization using MIP depends on the number of “integer” variables, e.g., whether or not a generator is committed. In order to solve the unit commitment optimization within a reasonable amount of computation time, inputs that involve unit commitment are defined in the CAISO’s PLEXOS model for generators that have a minimum output level greater than zero. That is,

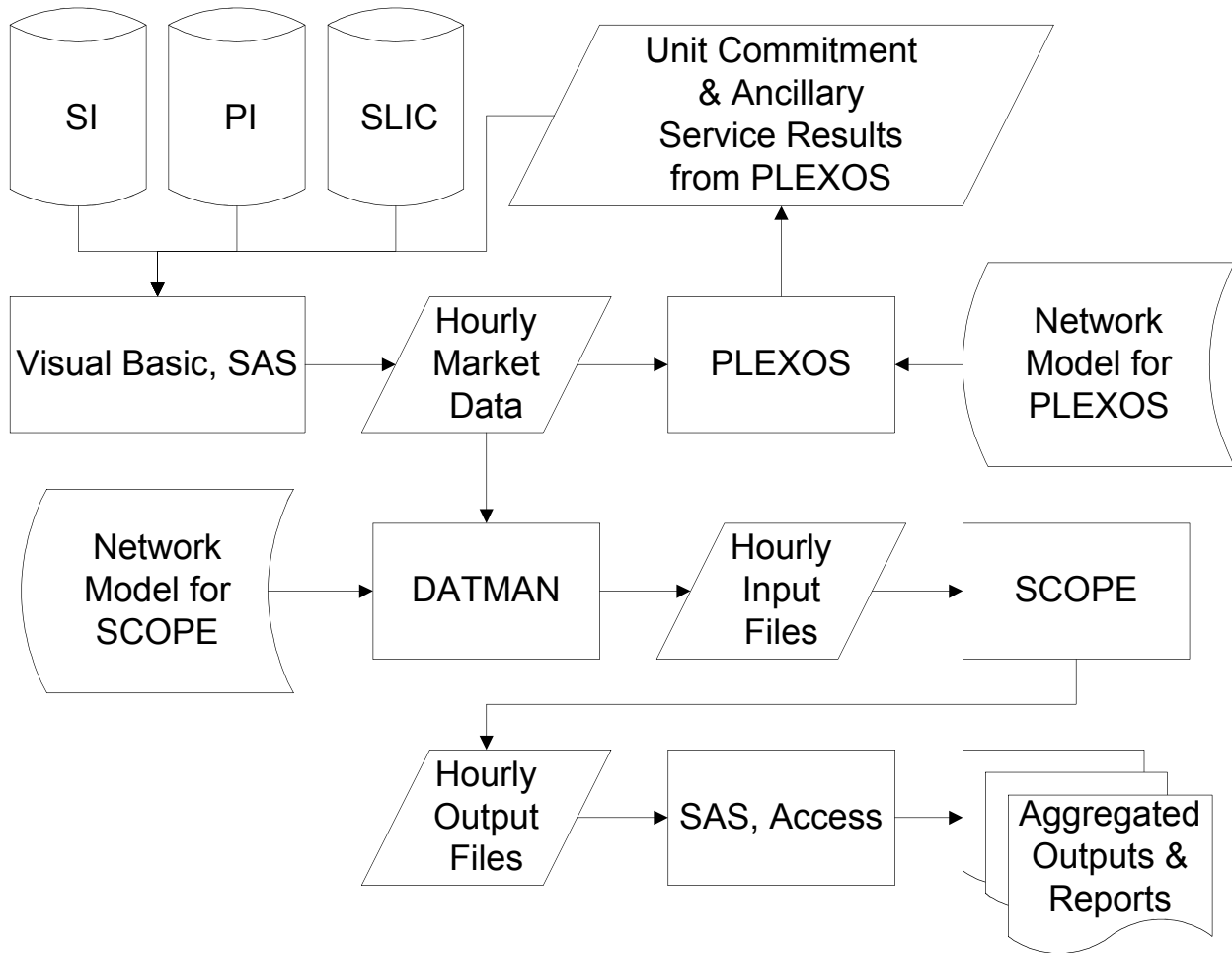
the CAISO has extended its Visual Basic and SAS scripts to produce files containing hourly data for input to PLEXOS, which links the hourly data to a static network model that is contained in a PLEXOS data file. Results of unit commitment and ancillary service reservations are extracted from the PLEXOS outputs, and merged with the market-related data that was used in LMP Study 3A, using the Visual Basic and SAS scripts. The result of this process is that the hourly market data that flows from the Visual Basic and SAS scripts into DATMAN, for preparation of the hourly input files to SCOPE, contains optimized unit commitment instructions instead of the assumptions that were necessary in LMP Study 3A. In addition, PLEXOS performs a co-optimization of ancillary service reservations and energy dispatch, using a network model³² and the DC OPF in PLEXOS, instead of today's determination of ancillary service reservations for simple congestion zones through a sequential market process of energy scheduling and ancillary service designations. Reservations of incremental capacity (i.e., spinning reserve, non-spinning reserve, and upward regulation) are removed from the maximum capacity of each affected generator's economic bid range, and reservations of decremental capacity (i.e., downward regulation) are removed from the minimum capacity of each affected generator's economic bid range

PLEXOS uses a DC OPF solution, so there is no difference in the results of optimization if a generator is de-committed, or if it remains committed but its output is reduced to zero MW – thus, commitment of a generator whose minimum output is essentially zero does not need to be optimized for purposes of this study. Also, if a generator always self-schedules its output, and its commitment is never affected by the CAISO's dispatch during a particular study period, its commitment does not need to be considered by the MIP optimization.

The processing time for a MIP optimization for unit commitment is also affected by the number of dispatch intervals over which the unit commitment is optimized. For initial months that are analyzed in LMP Study 3C, the CAISO is using PLEXOS with 24 one-hour dispatch intervals in each period over which unit commitment is optimized, starting at midnight. That is, PLEXOS is determining an optimized unit commitment over a 24-hour period, from midnight to midnight, with energy schedules being determined for each of the 24 hours.

³² The size of the network model used in PLEXOS is an additional influence on calculation time for the optimized unit commitment, and will be determined as the CAISO gains experience during LMP Study 3C. Initially, the CAISO is using a 385-bus equivalent of the full network model that is used in SCOPE, which may increase in size to ensure that it reflects all of the significant binding constraints that affect SCOPE's results. The CAISO will also be using PLEXOS to test proposals such as multi-day unit commitment, as well as the use of sub-hourly dispatch intervals in LMP Study 3C, which may require a smaller equivalent model; Appendix B presents Load Distribution Factors for both the 385-bus model and a 200-bus model that will be used for testing optimization periods with more dispatch intervals.

Figure 2: Process Flow for LMP Study 3C



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; specific details are described on the CAISO web site, including the MRTU Rollout Information page at <http://www.caiso.com/docs/2005/06/21/2005062113583824742.html>. For example, in the MRTU real-time market, a pre-dispatch process will run every 15 minutes to determine unit commitment decisions, and is followed by an economic dispatch process that will run every 5 minutes to determine final dispatch targets and LMPs.³³ The combined process for using PLEXOS and SCOPE is analogous to this multi-stage

³³ In addition to determining unit commitment, the forward market runs determine schedules for multiple levels of scheduling priorities (for example, Transmission Ownership Rights) in the event that economic bids are not sufficient to resolve congestion, but since the LMP Studies use real-time market conditions, different priorities of loads are not differentiated. Both the forward market and real-time pre-dispatch processes include local market power mitigation runs, which are not modeled

process, in using PLEXOS to determine unit commitment and then SCOPE to determine final dispatch points and LMPs using AC OPF. PLEXOS determines unit commitment decisions and ancillary service reservations that constrain the bids that SCOPE can use in determining the final LMPs.

The **total LMPs** for locations in the network (both LMPs for individual buses and load-weighted average prices) are disaggregated into separate **energy, congestion, and loss components**, for analysis and presentation where the separate components are referenced throughout this report. These components of the total LMP are calculated by:³⁴

- (1) subtracting a **loss component** from the **total LMP** (which is available from the SCOPE software as both individual bus prices and load-weighted averages by local load zone),
- (2) computing the load-weighted average of the remaining subtotal LMP (representing energy and congestion cost components, i.e., the total LMP minus the loss component), which is defined for purposes of this study as the **system's energy cost component**,³⁵ and
- (3) subtracting the system energy cost component from the subtotal LMP for each local load zone, to produce the **congestion component** of LMP for the zone relative to the system average.

The AC OPF solution in this study uses a distributed load slack variable rather than a single slack bus.³⁶ However, the version of the SCOPE software used in LMP Study 3A has stated the loss component relative to the reference bus used in power flow calculations for calculation of phase angles, which for purposes of this study is at Moss Landing; the CAISO was unable to readily convert this to a system average calculation, although for ultimate MRTU implementation the CAISO intends to state the loss

initially in LMP Study 3C. Modeling of local market power mitigation will be added as LMP Study 3C progresses, and will be described in a separate document.

³⁴ This multi-step process will be used in initial LMP Study 3C reports. Once a distributed reference for LMP disaggregation is implemented within the SCOPE software, this multi-step calculation may be unnecessary.

³⁵ Using a distributed load slack variable, as is done in this study, distributes the system slack MW among the loads in proportion to their MW values. Similarly, the use of a load-weighted average of the combined energy and congestion LMP components to define the reference energy price weights the nodal LMPs in the calculation in proportion to the MW load values. Thus, given that the loss LMP component remains relative to the single reference bus used to compute phase angles in the AC power flow calculations, the calculation of the energy and congestion components is similar to the result that would be obtained by using the distributed load slack variable as the reference energy price.

³⁶ In an AC power flow model, using a single slack bus means that adjustments to the MW output of system supply as a whole, to maintain a balance between supply and demand, occur using generation located at a single bus. When the results of an AC OPF market simulation are computed and a single slack bus is used in the power flow calculations, it is common to use the LMP at this bus as the system energy cost, since this is where incremental adjustments to supply occur to maintain the system power balance. Since changes in load at the slack bus will be met by changes in generation at the same bus, marginal losses are zero at the slack bus, and marginal losses at other buses are measured relative to the slack bus; this calculation of the LMP components is valid if and only if the change in supply occurs at the same location as the change in load. In contrast, a distributed generation slack variable makes adjustments to all generation to maintain the balance between supply and demand, instead of adjusting a single generator. A third AC power flow formulation is a distributed load slack variable, which makes proportional adjustments to loads throughout the system in order to maintain power balance. Based on initial concepts for the details of MRTU implementation when LMP Study 3A began, this study uses a distributed load slack variable.

component as each node's loss contribution to overall system losses.³⁷ In LMP Study 3C, the CAISO is working with Nexant, which is the vendor for SCOPE, to implement a distributed load reference for disaggregation of the loss component of LMPs.³⁸ Pending the completion and the CAISO's testing of this feature, LMP Study 3C modifies the loss component that was used in LMP Study 3A, to be as similar as possible to using a distributed load reference. This is done by (a) calculating a system-wide load-weighted average of the loss components as reported by SCOPE, and (b) observing that this load-weighted average can be used as an offset (i.e., an adder) to adjust the loss component at each bus or other location. That is, if the loss LMP component at each bus, as reported SCOPE (using versions prior to version 11.8), is $\text{LossLMP}_{\text{SCOPE}}$, and the weighted average of loss LMP components across the CAISO grid is $\text{LossLMP}_{\text{Average}}$, then the loss LMP component of each bus relative to the weighted average is $\text{LossLMP}_{\text{SCOPE}} - \text{LossLMP}_{\text{Average}}$.³⁹

As was done in the first published report in LMP Study 3A, the system average congestion component is defined to be zero for purposes of presentation in this study (that is, the reported results use a distributed slack bus), since the load-weighted average without losses has been defined to equal the system energy cost component. For each bus, the congestion component is then its LMP without losses, relative to the system energy component.

Additional discussion of the disaggregation of LMPs into LMP components is presented in Appendix A.

A final point of discussion concerning the "pricing run" using SCOPE is that under some system conditions, the AC power flow calculation does not readily converge to a solution. The approach to be used in the MRTU production software to address this possibility is to (1) first attempt an AC power flow solution with standard solution options and tolerances, then, (2) if the solution has not converged, attempt an AC power flow solution using relaxed solution options and tolerances, and finally, (3) if the relaxed AC power flow solution has not converged, rely on a DC power flow solution. In LMP Studies 3A and 3B, a considerable effort was used to reach AC OPF convergence with as little relaxation of solution options and tolerances as possible, which proved time-consuming even though an AC OPF solution was achieved in each hourly simulation. Therefore, to produce timely results in LMP Study 3C, the approach will be similar to what will be used in the MRTU production software: (1) first, attempt an AC OPF solution with standard options and tolerances, (2) second, attempt an AC OPF solution with relaxed options, and (3) finally, rely on a DC OPF solution if needed to obtain model convergence.⁴⁰ Because DC OPF does not produce a

³⁷ The impact of computing the loss component relative to a reference bus at Moss Landing, instead of relative to the distributed load slack variable, may be minimal, but cannot be determined at the outset of this study, but will be examined during the study. The MRTU production software will provide both the loss and congestion components relative to a system-wide reference quantity, not relative to a single reference bus.

³⁸ Version 11.8 of SCOPE has been released shortly before publication of this document, and is currently being tested by the CAISO.

³⁹ Since the values of $\text{LossLMP}_{\text{SCOPE}}$ are based on a single reference bus at Moss Landing, $\text{LossLMP}_{\text{SCOPE}}$ equals zero at this reference bus. The recalculated loss component at the Moss Landing reference bus is $\text{LossLMP}_{\text{SCOPE}} - \text{LossLMP}_{\text{Average}} = 0 - \text{LossLMP}_{\text{Average}}$, which equals $-\text{LossLMP}_{\text{Average}}$.

⁴⁰ If it is necessary to use a DC OPF solution, the local area loads will include losses.

loss component of LMP, the reported results will use the loss factors (as percentages) from the most recent successful AC OPF solution.⁴¹

Limitations of Modeling

Although the CAISO has made every reasonable effort to develop a simulation approach that is realistic and that models the CAISO's market as accurately as possible using the currently available information, any modeling effort unavoidably has limitations and relies on extensive assumptions. The improvements in methodology in LMP Study 3C, compared to Studies 3A and 3B, have reduced the limitations of the CAISO's modeling. The analysis presented herein seeks to determine what market prices would have occurred if certain features of the MRTU market design had been in place, but it is important to recognize that this analysis is not a forecast of LMPs under future market conditions. Although this study uses actual market bids and operating constraints, the model results may vary from actual operations, during either the current market structure or the MRTU market, for several reasons. In summary:

- First, the modeling in this study assumes that all final hour-ahead schedules and all bids offered in the real-time market are operationally feasible with respect to the resources' operating capabilities, and that generators operate in perfect compliance with their schedules and dispatch instructions.⁴²
- The CAISO's operators can recognize real-time conditions that would make some bids infeasible or ineffective in meeting system needs (e.g., some bids need to be skipped to preserve operating reserve), and thus bypass some bids in real-time operations. The CAISO's operators also issue requests for schedule changes due to foreseeable system conditions (e.g., implementation of unscheduled flow mitigation procedures in regional inter-ties), which cannot be considered when this study's model uses the available real-time bids. Similarly, using market bids does not consider all potential out-of-market dispatch instructions or start-up instructions to quick-start must-offer generators.
- Real-time market bids that are based on a zonal market design may not reflect how market participants would bid in a nodal market design, particularly if they have local market power. Also, the study models only the CAISO's real-time energy market, because only real-time market bids are currently available. The complete CAISO marketplace under MRTU will include sequential markets (a Day-Ahead energy market in addition to the real-time market), each with its own LMPs that will be used to price a portion of the actual energy that is ultimately consumed. Changing

⁴¹ If it is necessary to use a DC OPF solution, the loss factors may not correspond exactly to the total LMP, but the congestion LMP component should not be recalculated because it is the product of the shadow price of binding constraints and the Power Transfer Distribution Factor (PTDF, or "shift factor") of each bus relative to the binding constraints. Thus, the energy component may vary between buses, instead of being equal at all buses as it would be in a successful AC OPF solution.

⁴² The assumption that schedules and bids are "operationally" feasible does not refer to whether schedules and bids, taken together, are within the transmission limits. Market participants generally do not have the ability to limit their submitted schedules and bids to the feasible transmission limits (unless intertie or other path restrictions have been published by the CAISO), since they do not know other market participants' schedules and bids and have incomplete knowledge of outages, but could be expected to schedule and bid only amounts that they could physically deliver if there were no transmission limits.

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from a zonal to a nodal market design may change bidding behavior, and bidding in a forward market may differ from bidding in a real-time market.

- Incorporation of transmission outages has been limited by the time required for manual review of outage records.
- At present the distribution of loads within load aggregation areas (including some local areas) is based simply on a static distribution contained in the network model, since validation of the CAISO's state estimator's solutions is an ongoing process.
- Finally, the CAISO is in the midst of an extensive effort to validate and improve the data that comprises its network model, and imperfections in the input data will affect the results of the modeling.

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Appendix A

Disaggregation of LMP Components

This Appendix presents additional detail concerning disaggregation of LMPs into LMP components (i.e., energy, losses, and congestion), beyond the general description in the body of this report. Along with illustrating the methodologies that are used in LMP Study 3C, this discussion addresses questions that have arisen during stakeholder discussions concerning whether the relative Loss component of LMPs among buses is sensitive to selection of the reference bus. This issue is important to simulation of the functioning of MRTU because while MW injections by generators and withdrawals by loads will be settled at total LMPs, and the three components of LMPs add up to the total LMP (Total LMP = Energy + Loss + Congestion), some aspects of financial settlements are based on components of the LMPs. In particular, settlements of Congestion Revenue Rights (CRRs) are based on the congestion component, and exclude the loss component. If the formulation of the LMP model causes variations among the relative values of the loss component at different locations (that is, if the loss component between locations does not maintain a simple \$/MWh difference), the variation would affect congestion revenues and therefore the value of CRRs.

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

1. Angle reference: In power flow calculations, the distribution of flows throughout the network involves calculation of phase angles, which are measured from a single reference location. There must be a single angle reference bus for the entire system (unless the system has multiple islands, in which case each island would have an angle reference bus). Although the angle reference bus is essential to power flow calculations, the CAISO's intent in specifying the MRTU design is that the selection of the angle reference bus should not affect the prices that result from the market. Keeping the market results independent of the choice of angle reference bus involves the definition of the other reference variables for system power balance and LMP disaggregation.
2. System power balance: In an AC power flow model, among the solution options is the use of a single bus or a "distributed" slack variable for system power balance. Using a single slack bus means that adjustments to the MW output of system supply as a whole, to maintain a balance between supply and demand, occur using generation located at a single bus. When the results of an AC OPF market simulation are computed and a single slack bus is used in the power flow

calculations, it is common to use the LMP at this bus as the system energy cost, since this is where incremental adjustments to supply occur to maintain the system power balance. Since changes in load at the slack bus will be met by changes in generation at the same bus, marginal losses are zero at the slack bus, and marginal losses at other buses are measured relative to the slack bus; this calculation of the LMP components is valid if and only if the change in supply occurs at the same location as the change in load.⁴³ In contrast, a distributed generation slack variable makes adjustments to all generation to maintain the balance between supply and demand, instead of adjusting a single generator. A third AC power flow formulation is a distributed load slack variable, which makes proportional adjustments to loads throughout the system in order to maintain power balance. When a distributed slack variable is used (either a distributed generation slack or a distributed load slack), adjustments to maintain the system power balance are independent of the choice of angle reference bus because they occur throughout the network. This study uses a distributed load slack variable.

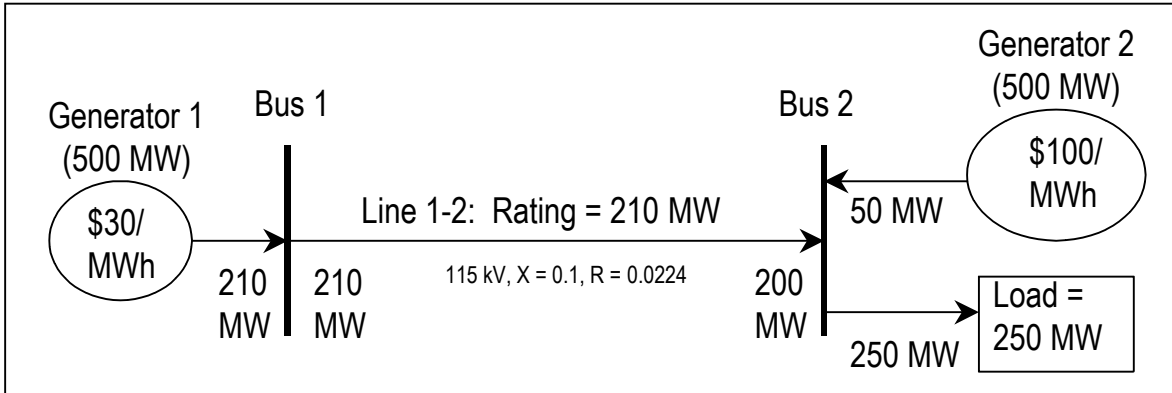
3. LMP disaggregation: The third reference variable involves the definition of the energy and loss components on LMPs: the energy component is the same at all locations in the network and is defined by the distribution of either generation or load, and the loss component is similarly defined as a measurement of the system's response to changes in injections or withdrawals that are distributed throughout the network. The concept of computing LMP components at a single reference bus, versus using a distributed reference that reflects adjustments that are spread throughout the network, is similar to the slack reference that is used for system power balance. The calculations of system power balance and LMP disaggregation can occur separately, but there is little reason (other than software configuration) to measure LMP components using a different reference than the power balance equations. As is the case when a distributed slack variable is used for maintaining system power balance, the results of LMP disaggregation are independent of the choice of angle reference bus because the reference variable is distributed throughout the system. This meets the CAISO's intent, in the MRTU design, that the selection of the angle reference bus should not affect the prices that result from the market.⁴⁴

The distinctions among these quantities can be seen by considering a two-bus example, in which 500 MW generators are located at both Bus 1 and Bus 2, which have a \$30/MWh bid at Bus 1 and a \$100/MWh bid at Bus 2. There is a load of 250 MW at Bus 2. The transmission line from Bus 1 to Bus 2 has impedances as shown, and a rating of 210 MW at each end. Each generator has a large reactive generation capability, and controls its own bus voltage to 1.0 per-unit.

⁴³ When changes in load at the slack bus are matched by changes in generation at the same bus, flows between other buses in the network do not change, losses in the system do not change, and marginal losses are zero. However, if the change in load at one bus are matched by changes in generation at other buses, then flows in the network do change, which causes losses in the system as a whole to change, and marginal losses (i.e., the change in system losses per increment of change in load) are not zero.

⁴⁴ The independence of the LMP disaggregation using a distributed reference variable from the selection of angle reference bus is both a theoretical result, since the distribution of load or generation is not affected by the choice of angle reference bus, and an empirical result that appears in the outputs of LMP software.

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

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

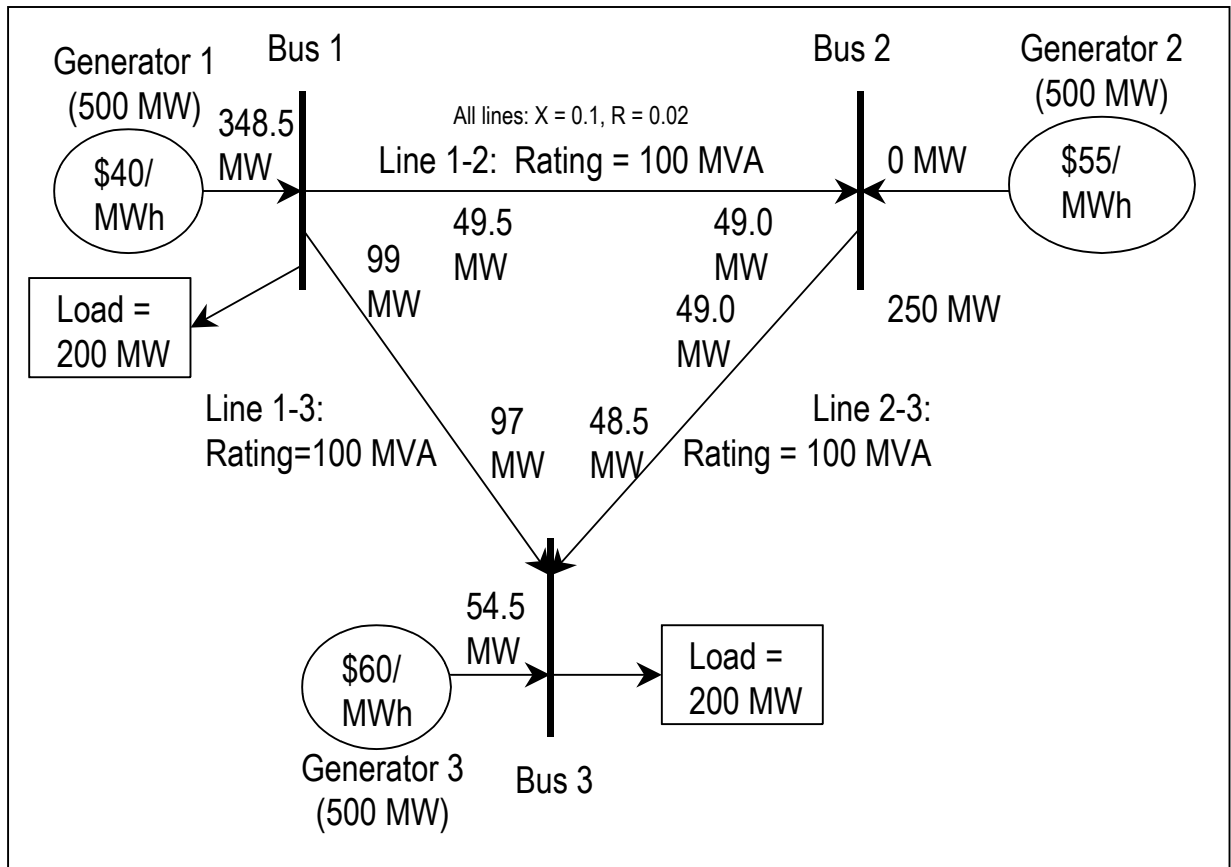
In the first model formulation, LMP components are computed using a single bus (Bus 1) as the reference for LMP disaggregation, and the angle reference bus is Bus 1. The difference between the LMP loss components at the two buses is \$3.12/MWh. In the second model formulation, Bus 2 is the single reference bus for LMP disaggregation, and Bus 2 is the angle reference bus. The difference between the LMP loss components at the two buses is \$9.41/MWh, which is three times as high as in the first model formulation. The shadow price of the constrained line limit is \$60.59 regardless of the choice of reference bus or LMP reference formulation.

The shadow price of the constraint (\$60.59/MW) is the marginal value of changing the constraint's limit by 1 MW. The constraint limit applies at each end of the line from Bus 1 to Bus 2, and is a binding constraint at Bus 1, where the flow is higher. When the model uses a single reference bus at Bus 2, the

difference between congestion prices at the two buses is stated as a non-zero price at Bus 1, and the difference in congestion prices equals the shadow price of the constraint since the constraint is limiting flows at the same location. When the model uses a single reference bus at Bus 1, the difference between congestion prices at the two buses is stated as a non-zero price at Bus 2, and is stated relative to the flows on the constrained line at the same location (i.e., Bus 2). Relative to the reference bus at Bus 1, the “loss penalty factor” at Bus 2 is 0.9059: if the flow at Bus 1 were increased by an increment of 1 MW, the incremental change in flow at Bus 2 would be 0.9059 MW, after losses in the line. That is, an additional 0.9059 MW of load at Bus 2 could be served by the less expensive generator at Bus 1, if the constraint limit at Bus 1 were increased by 1 MW. The incremental savings to the system is the shadow cost of the 1 MW relief in the constraint (\$60.59) per 0.9059 MW of load at Bus 2, so the congestion price difference between Bus 1 and Bus 2 is $\$60.59 / 0.9059 \text{ MW} = \$66.88/\text{MWh}$ (using a 1-hour dispatch interval).

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

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



Generators 1, 2, and 3 (located at Buses 1, 2, and 3, respectively) each have 500 MW capacity, and have bids of \$40, \$55, and \$60/MWh, respectively. Buses 1 and 3 each have 200 MW of load. Lines 1-2, 1-3, and 2-3 have equal impedances, and ratings of 100 MVA each. Generator 1 can serve all of the load at Bus 1, but can only produce 148.5 MW to serve the load at Bus 3 because of the limit on Line 1-3's capacity. (Because MVA reactive power flows in addition to MW power flows, the 100 MVA capacity amounts to only 99 MW of real power.)

For the alternative model formulations of single-bus or distributed LMP disaggregation, and selections of angle reference bus, the disaggregated LMP results are as follows:⁴⁵

⁴⁵ Some values in this table are affected by rounding by the AC OPF software that was used to compute these comparisons.

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

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

Pending the availability (and completion of the CAISO's testing) of the distributed load reference for LMP disaggregation in SCOPE, the CAISO is using an approximation of the LMP component revenues

in initial LMP Study 3C reports.⁴⁶ This approximation is based on the observation that the load-weighted average loss component is close to \$0/MWh when a distributed load reference has been used. As described in the “Pricing Run” section of the body of this report, as an interim step in its initial reports of results, initial reports in LMP Study 3C modify the loss component that was used in LMP Study 3A, to be as similar as possible to using a distributed load reference. This is done by (a) calculating a system-wide load-weighted average of the loss components as reported by SCOPE, and (b) observing that this load-weighted average can be used as an offset (i.e., an adder) to adjust the loss component at each bus or other location. That is, if the loss LMP component at each bus, as reported by SCOPE (using versions prior to version 11.8), is $\text{LossLMP}_{\text{SCOPE}}$, and the weighted average of loss LMP components across the CAISO grid is $\text{LossLMP}_{\text{Average}}$, then the loss LMP component of each bus relative to the weighted average is $\text{LossLMP}_{\text{SCOPE}} - \text{LossLMP}_{\text{Average}}$. Using the results of the three-bus example above, the following table illustrates the series of calculations used in initial LMP Study 3C reports:

⁴⁶ Version 11.8 of SCOPE became available shortly before publication of this document, and implements distributed reference variables for LMP disaggregation. The CAISO is currently verifying initial results using this version of SCOPE, so that it can be used for future LMP Study reports.

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	LMP Reference and Angle Reference at Bus 1			LMP Reference and Angle Reference at Bus 2			LMP Reference and Angle Reference at Bus 3		
	LMP at Bus 1	LMP at Bus 2	LMP at Bus 3	LMP at Bus 1	LMP at Bus 2	LMP at Bus 3	LMP at Bus 1	LMP at Bus 2	LMP at Bus 3
Load	200	0	200	200	0	200	200	0	200
Total LMP (\$/MWh)	40	49.9	60	40	49.9	60	40	49.9	60
Energy LMP Component (\$/MWh)	40	40	40	49.9	49.9	49.9	60	60	60
Loss LMP Component (LossLMP _{SCOPE}) (\$/MWh)	0	0.83	1.67	-1.02	0	1.03	-2.41	-1.21	0
Congestion LMP Component (\$/MWh)	0	9.07	18.33	-8.89	0	9.07	-17.59	-8.89	0
System Average Loss Component (LossLMP _{Average})	0.835	0.835	0.835	0.005	0.005	0.005	-1.205	-1.205	-1.205
Recalculated Loss LMP Component (LossLMP _{SCOPE} – LossLMP _{Average})	-0.835	-0.005	0.835	-1.025	-0.005	1.025	-1.205	-0.005	1.205
Subtotal: Energy + Congestion Components (equal to Total LMP – Recalculated Loss Component)	40.835	49.905	59.165	41.025	49.905	58.975	41.205	49.905	58.795
Recalculated System Average Energy Component (load-weighted average of energy + congestion components)	50	50	50	50	50	50	50	50	50
Recalculated Congestion Component (Total LMP – Energy – Loss)	-9.165	-0.095	9.165	-8.975	-0.095	8.975	-8.795	-0.095	8.795

These calculations have not eliminated differences among the loss LMP component values (and the offsetting differences among the congestion component values), but the relative levels of the energy, loss, and congestion components have been brought to approximately the same value as if a distributed reference had been used for the LMP disaggregation, regardless of which bus is used as the angle

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reference bus. It is notable that the variation in LMP components is a small fraction of the congestion prices, even though it is more significant as a percentage of the loss component. Eliminating the dependence of differences among the loss LMP component values will require the use of the distributed reference for LMP disaggregation, and the CAISO will begin to use this formulation once it is available in SCOPE.

The prices discussed in the above examples have been calculated using commercially available AC OPF software other than SCOPE.⁴⁷ Remaining questions are whether variations among LMP components are as affected by the selection of the reference bus as the two-bus and three-bus examples are, and whether the published results in the CAISO's LMP Studies have successfully reflected congestion price patterns. Examples using small networks can show theoretical impacts, but in practice the generation and loads (and flows from generation to loads) are distributed throughout a complex network. Also, the CAISO's LMP Studies may have succeeded in reducing the impact of the selection of the angle reference bus by using a distributed load slack for power balance, even though the distributed reference was not available for LMP disaggregation. To explore these issues in context of the CAISO's LMP Studies, the CAISO has examined its model's sensitivity to the selection of the angle reference bus, using a case from LMP Study 3B (12/16/2003, Hour 23). In this case, a single constraint is congested: Path 26 is derated to 500 MW due to a forced outage on the Midway to Vincent #3 500 kV line.

In the following table, the loss LMP component has been recalculated using alternative locations for the angle reference bus, which is also used as the single-bus reference for LMP disaggregation:

Loss Component of LMP at alternative reference bus locations (\$/MWh)						
LMP Location (Bus Number and Name)	Local Load Zone	Angle Reference Bus				
		Encina 5	Huntington Beach 2	Pittsburg 7	Moss Landing 1	Diablo Canyon 2
22244 ENCINA 5	SDG&E	\$0.00	\$-1.08	\$-1.60	\$0.10	\$-0.31
24067 HUNT 2	LA/ Orange	1.11	0.00	-0.88	0.81	0.40
30000 PTSB 7	East Bay	1.63	0.47	0.00	1.76	1.23
36221 DUKMOSS1	Central Coast	0.14	-0.98	-1.67	0.00	-0.44
36412 DIABLO 2	ZP26	0.51	-0.59	-1.28	0.43	0.00

In the above table, the values are the loss LMP component using several alternative reference bus locations, where the LMP disaggregation uses a single-bus reference (located at the angle reference bus) but a distributed load slack is used for power balance. The loss component of LMPs is stated at the same locations as the alternative reference buses. Within each column (which presents results of the AC OPF solution using an alternative angle reference bus), the loss LMP component is \$0 at the reference bus, and rows of LMP results at other locations show the value of marginal losses at those locations, relative to the angle reference bus location. Because different locations have different marginal loss values, it is not surprising that there is variation among the numbers in the above table.

To approximate the results that would occur on a comparable basis, in which the same reference point is used for LMP disaggregation while the angle reference bus is varied, the values in the following table have adjustments to each column of loss LMPs (i.e., for each model run that uses a different angle

⁴⁷ Initial testing of SCOPE version 11.8 has produced essentially the same results for these examples.

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reference bus), which apply a constant adder to bring the loss LMP component at Moss Landing to \$0/MWh.⁴⁸ Although there is significant variation among loss LMP component values in the raw outputs from SCOPE,⁴⁹ most of the variation disappears when the values are recalculated to express the loss LMP component on a consistent basis that does not vary with the selection of the angle reference bus. This can be seen in the similarity of values across each row of the following table: the loss LMP component has similar values regardless of the choice of reference bus.

Change in Loss Component of LMP relative to reference at Moss Landing (\$/MWh)						
LMP Location (Bus Number and Name)	Local Load Zone	Angle Reference Bus				
		Encina 5	Huntington Beach 2	Pittsburg 7	Moss Landing 1	Diablo Canyon 2
22244 ENCINA 5	SDG&E	\$-0.14	\$-0.10	\$0.07	\$0.10	\$0.13
24067 HUNT 2	LA/ Orange	0.96	0.98	0.81	0.81	0.84
30000 PTSB 7	East Bay	1.49	1.45	1.76	1.76	1.67
36221 DUKMOSS1	Central Coast	0	0	0	0	0
36412 DIABLO 2	ZP26	0.37	0.39	0.43	0.43	0.44

In summary, this appendix has described the mechanics of LMP disaggregation, at a general level, and explored the sensitivity of LMP components to the method of calculating the LMP disaggregation. Calculations of LMP components that do not vary with the selection of the angle reference bus require the use of a distributed reference for LMP disaggregation, as the CAISO is implementing in its MRTU production software. The CAISO's LMP Studies have used a distributed load slack for power balance calculations, so that the response of system dispatch reduces the results' dependence on the selection of the angle reference bus. The purpose of LMP Study reports to date has been to examine congestion cost variations, and the CAISO's approach to recalculating LMP components has limited the dependence of these results to the selection of the reference bus. Initial reports in LMP Study 3C extend the recalculation process to the loss component, so that total loss revenues approximate what would result from using a distributed load reference for LMP disaggregation. For subsequent reports in LMP Study 3C, the CAISO is preparing to implement a distributed load reference for LMP disaggregation, so that both loss and congestion prices can be accurately compared.

⁴⁸ This is a similar process to the recalculations that are done in initial reports in LMP Study 3C. In the results published in these reports, a constant adder is applied to set the load-weighted average loss LMP component to \$0/MWh. This is done to approximate the results of using a distributed load reference for LMP disaggregation.

⁴⁹ Because the absolute level of the loss component varies with the selection of the reference bus, when a single reference bus is used, calculations of total revenue collected by the different LMP components have little meaning if they are based on a single reference bus.

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Appendix B Load Distribution Factors for Reduced Equivalent Network Model

As noted in the body of this document, reduced equivalent network models are used in PLEXOS for performance reasons during the determination of unit commitment using Mixed Integer Programming. Initially, a 385-bus equivalent of the CAISO network and external scheduling points is being used for preparing the regular LMP Study results, and a 200-bus model has been identified for testing of extended unit commitment periods. The buses comprising these models, and the associated Load Distribution Factors (LDFs) at each bus, within the areas where area loads are calculated, are as follows.

Bus	Demand Zone	Load Calculation Area	Local Load Zone (or Scheduling Point)	Load Distribution Factor (385-bus Model)	Load Distribution Factor (200-bus Model)
31000HUMBOLDT	PGE1	Humboldt	PGHB Humboldt	0.7355245	1.0000000
31015BRDGVILLE	PGE1	Humboldt	PGHB Humboldt	0.1261632	
31118KEKAWAKA	PGE1	Humboldt	PGHB Humboldt	0.1383123	
30685EMBRCDRD	PGE2	San Francisco	PGSF San Francisco	0.1001418	
30690EMBRCDRE	PGE2	San Francisco	PGSF San Francisco	0.1001418	
30695MARTIN C	PGE2	San Francisco	PGSF San Francisco	0.0000000	0.2083960
33203MISSION	PGE2	San Francisco	PGSF San Francisco	0.1914487	0.2135610
33204POTRERO	PGE2	San Francisco	PGSF San Francisco	0.1769860	0.1999010
33205HNTRS PT	PGE2	San Francisco	PGSF San Francisco	0.0443932	
33206BAYSHOR1	PGE2	San Francisco	PGSF San Francisco	0.0041422	0.0043106
33207BAYSHOR2	PGE2	San Francisco	PGSF San Francisco	0.0057999	0.0060388
33208MARTIN C	PGE2	San Francisco	PGSF San Francisco	0.3145266	0.3677925
33307MILLBRAE	PGE2	San Francisco	PGSF San Francisco	0.0624199	
30437CROCKETT	PGE3	Bay Area	PGEB East Bay	0.0004452	0.0004625
30525C.COSTA	PGE3	Bay Area	PGEB East Bay	0.0439053	0.0478991
30527PITSBG E	PGE3	Bay Area	PGEB East Bay	0.0165824	0.0165973
30535TIDEWATR	PGE3	Bay Area	PGEB East Bay	0.0311232	0.0311310
30540SOBRANTE	PGE3	Bay Area	PGEB East Bay	0.0000000	0.0588288
30550MORAGA	PGE3	Bay Area	PGEB East Bay	0.0194440	0.0758957
30554CASTROVL	PGE3	Bay Area	PGEB East Bay	0.0099170	0.0099264

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30555SANRAMON	PGE3	Bay Area	PGEB East Bay	0.0319978	0.0320205
30560E. SHORE	PGE3	Bay Area	PGEB East Bay	0.0129840	0.0213310
30575WND MSTR	PGE3	Bay Area	PGEB East Bay	0.0000000	0.0000000
30585LS PSTAS	PGE3	Bay Area	PGEB East Bay	0.0175503	0.0177820
30595FLOWIND2	PGE3	Bay Area	PGEB East Bay	0.0000905	0.0010656
30630NEWARK D	PGE3	Bay Area	PGEB East Bay	0.0394618	0.1108300
30655ADCC	PGE3	Bay Area	PGEB East Bay	0.0009065	
32778MRTNZJCT	PGE3	Bay Area	PGEB East Bay	0.0134772	
32780CLARMNT	PGE3	Bay Area	PGEB East Bay	0.0279200	
32786OAK C115	PGE3	Bay Area	PGEB East Bay	0.0430681	
32950PITSBURG	PGE3	Bay Area	PGEB East Bay	0.0502235	0.0841178
32971MEDW LNE	PGE3	Bay Area	PGEB East Bay	0.0350424	
32990MARTNZ D	PGE3	Bay Area	PGEB East Bay	0.0209200	0.0395115
33010SOBRANTE	PGE3	Bay Area	PGEB East Bay	0.0480417	
30042METCALF	PGE3	Bay Area	PGME Metcalf	0.0000000	0.0000000
30735METCALF	PGE3	Bay Area	PGME Metcalf	0.0074629	0.1064254
30700SANMATEO	PGE3	Bay Area	PGP2 Peninsula	0.0000000	0.0000000
30703RAVENSWD	PGE3	Bay Area	PGP2 Peninsula	0.0000000	0.0478866
30705MONTAVIS	PGE3	Bay Area	PGP2 Peninsula	0.0278838	0.0916444
30715JEFFERSN	PGE3	Bay Area	PGP2 Peninsula	0.0179368	0.0190148
30730HICKS	PGE3	Bay Area	PGP2 Peninsula	0.0192692	
30741CAL MEC	PGE3	Bay Area	PGP2 Peninsula	0.0000000	0.0000000
33310SANMATEO	PGE3	Bay Area	PGP2 Peninsula	0.0374575	0.0630092
33313BAIR	PGE3	Bay Area	PGP2 Peninsula	0.0164931	
33315RAVENSWD	PGE3	Bay Area	PGP2 Peninsula	0.0541140	
30731LS ESTRS	PGE3	Bay Area	PGSB South Bay	0.0010183	0.1013484
35120NEWARK D	PGE3	Bay Area	PGSB South Bay	0.0474765	
35356MNTA VSA	PGE3	Bay Area	PGSB South Bay	0.0471006	
35363LAWRENCE	PGE3	Bay Area	PGSB South Bay	0.0175743	
35604ZANKER	PGE3	Bay Area	PGSB South Bay	0.0058676	
35610MONTAGUE	PGE3	Bay Area	PGSB South Bay	0.0247368	
35615FMC	PGE3	Bay Area	PGSB South Bay	0.0248262	
35632MARKHAM	PGE3	Bay Area	PGSB South Bay	0.0240878	
35642MTCALF D	PGE3	Bay Area	PGSB South Bay	0.0689543	
35647GILROY	PGE3	Bay Area	PGSB South Bay	0.0143648	0.0232718
35658LS ESTRS	PGE3	Bay Area	PGSB South Bay	0.0175601	
36850KIFER	PGE3	Bay Area	PGSB South Bay	0.0248506	
36851NORTHERN	PGE3	Bay Area	PGSB South Bay	0.0210499	
36852SCOTT	PGE3	Bay Area	PGSB South Bay	0.0168143	
30790PANOCH	PGE3	Fresno	PGF1 Fresno	0.0067738	0.0987551
30800WILSON	PGE3	Fresno	PGF1 Fresno	0.0091490	0.1456657
30810GREGG	PGE3	Fresno	PGF1 Fresno	0.1088898	0.3876626
30820HELMS PP	PGE3	Fresno	PGF1 Fresno	0.0000000	0.0000000
30830KEARNEY	PGE3	Fresno	PGF1 Fresno	0.0303884	
30835HERNDON	PGE3	Fresno	PGF1 Fresno	0.0540438	
30855HAAS	PGE3	Fresno	PGF1 Fresno	0.0000000	

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30865BALCH	PGE3	Fresno	PGF1 Fresno	0.0000000	0.0000000
30870PINE FLT	PGE3	Fresno	PGF1 Fresno	0.0000000	
30875MC CALL	PGE3	Fresno	PGF1 Fresno	0.0000000	0.3023628
30881HENRIETA	PGE3	Fresno	PGF1 Fresno	0.0461137	0.0655539
34100CHWCHLLA	PGE3	Fresno	PGF1 Fresno	0.0128033	
34116LE GRAND	PGE3	Fresno	PGF1 Fresno	0.0227979	
34134WILSON A	PGE3	Fresno	PGF1 Fresno	0.1022991	
34156MENDOTA	PGE3	Fresno	PGF1 Fresno	0.0318241	
34158PANOCHE	PGE3	Fresno	PGF1 Fresno	0.0521552	
34168EL NIDO	PGE3	Fresno	PGF1 Fresno	0.0135694	
34358KERCKHF2	PGE3	Fresno	PGF1 Fresno	0.0463209	
34366SANGER	PGE3	Fresno	PGF1 Fresno	0.1241045	
34370MC CALL	PGE3	Fresno	PGF1 Fresno	0.1315673	
34372MALAGA	PGE3	Fresno	PGF1 Fresno	0.0344498	
34386KNGSCOGN	PGE3	Fresno	PGF1 Fresno	0.0211165	
34398BALCH	PGE3	Fresno	PGF1 Fresno	0.0001204	
34400KNGSRVR1	PGE3	Fresno	PGF1 Fresno	0.0096862	
34412HERNDON	PGE3	Fresno	PGF1 Fresno	0.1321093	
34429GWF_HEP	PGE3	Fresno	PGF1 Fresno	0.0097175	
30403GEYSR16	PGE3	South Geysers	PGFG Geysers	0.0000000	
30430FULTON	PGE3	South Geysers	PGFG Geysers	0.7347153	1.0000000
32560MNTCLOPH	PGE3	South Geysers	PGFG Geysers	0.0523444	
32564PUEBLO	PGE3	South Geysers	PGFG Geysers	0.2129403	
31200MENDOCNO	PGE3	North Coast	PGNC North Coast	0.3217741	0.6196552
31204UKIAH	PGE3	North Coast	PGNC North Coast	0.2855981	
31220EGLE RCK	PGE3	North Coast	PGNC North Coast	0.2279091	0.3803448
31224INDIN VL	PGE3	North Coast	PGNC North Coast	0.0315952	
31226HGHLAND	PGE3	North Coast	PGNC North Coast	0.1331236	
32018GOLDHILL	PGE3	Sierra	PGSI Sierra	0.2598695	0.3674185
32218DRUM	PGE3	Sierra	PGSI Sierra	0.0714434	0.1431579
32224CHCGO PK	PGE3	Sierra	PGSI Sierra	0.0300501	
32228PLACER	PGE3	Sierra	PGSI Sierra	0.3371659	0.3478446
32252APPLE HL	PGE3	Sierra	PGSI Sierra	0.0953194	0.1362657
32264CLRKSVLT	PGE3	Sierra	PGSI Sierra	0.0029503	0.0053133
32265SHPRING	PGE3	Sierra	PGSI Sierra	0.1507623	
32374DRUM	PGE3	Sierra	PGSI Sierra	0.0524390	
31594VOLTA	PGE3	Other PG&E	PGBC Battle Creek	0.0044183	
30045MOSSLAND	PGE3	Other PG&E	PGCC Central Coast	0.0028548	0.0030445
30750MOSSLND2	PGE3	Other PG&E	PGCC Central Coast	0.0016798	0.0018547
30755MOSSLND1	PGE3	Other PG&E	PGCC Central Coast	0.0016807	0.0018547
30760COBURN	PGE3	Other PG&E	PGCC Central Coast	0.0100563	0.0107240
35907PAUL SWT	PGE3	Other PG&E	PGCC Central Coast	0.0172725	
35918SALINAS2	PGE3	Other PG&E	PGCC Central Coast	0.0254166	
35919SOLEDAD	PGE3	Other PG&E	PGCC Central Coast	0.0068329	
35922MOSLND D	PGE3	Other PG&E	PGCC Central Coast	0.0229494	0.0774050
30348BRIGHTON	PGE3	Other PG&E	PGDE Delta	0.0037594	0.0172616

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31970WOODLAND	PGE3	Other PG&E	PGDE Delta	0.0159054	0.0338139
31990DAVIS	PGE3	Other PG&E	PGDE Delta	0.0259978	
31994GRAND IS	PGE3	Other PG&E	PGDE Delta	0.0041086	
32200PEASE	PGE3	Other PG&E	PGDE Delta	0.0144059	0.0157136
32212E.NICOLS	PGE3	Other PG&E	PGDE Delta	0.0052850	0.0062557
32214RIO OSO	PGE3	Other PG&E	PGDE Delta	0.0055768	0.0081387
30395GEYSR18	PGE3	Other PG&E	PGNB North Bay	0.0000000	0.0000000
30435LAKEVILE	PGE3	Other PG&E	PGNB North Bay	0.0327961	0.0514762
30440TULUCAY	PGE3	Other PG&E	PGNB North Bay	0.0110297	
30445IGNACIO	PGE3	Other PG&E	PGNB North Bay	0.0381636	0.0406955
30465BAHIA	PGE3	Other PG&E	PGNB North Bay	0.0139481	
30005ROUND MT	PGE3	Other PG&E	PGNV North Valley	0.0000000	0.0000000
30015TABLE MT	PGE3	Other PG&E	PGNV North Valley	0.0000000	0.0000000
30105COTWD_E	PGE3	Other PG&E	PGNV North Valley	0.0145501	0.0337714
30106COTWD_F	PGE3	Other PG&E	PGNV North Valley	0.0000000	
30108BRNY_FST	PGE3	Other PG&E	PGNV North Valley	0.0000000	
30110GLENN	PGE3	Other PG&E	PGNV North Valley	0.0118926	
30185PIT 1	PGE3	Other PG&E	PGNV North Valley	0.0018486	
30190SPI-BRNY	PGE3	Other PG&E	PGNV North Valley	0.0002742	
30195PIT 3	PGE3	Other PG&E	PGNV North Valley	0.0001916	
30200PIT 4	PGE3	Other PG&E	PGNV North Valley	0.0000000	
30205BLACK	PGE3	Other PG&E	PGNV North Valley	0.0000000	
30210PIT 5 JT	PGE3	Other PG&E	PGNV North Valley	0.0000280	
30215PIT 6	PGE3	Other PG&E	PGNV North Valley	0.0000000	
30220PIT 7	PGE3	Other PG&E	PGNV North Valley	0.0000000	
30245ROUND MT	PGE3	Other PG&E	PGNV North Valley	0.0000000	0.0015355
30250CARIBOU	PGE3	Other PG&E	PGNV North Valley	0.0011442	0.0109864
30260BELDEN	PGE3	Other PG&E	PGNV North Valley	0.0000000	
30265BCKS CRK	PGE3	Other PG&E	PGNV North Valley	0.0002457	
30268ROCKCK 1	PGE3	Other PG&E	PGNV North Valley	0.0000000	
30270ROCKCK 2	PGE3	Other PG&E	PGNV North Valley	0.0000000	
30275CRESTA	PGE3	Other PG&E	PGNV North Valley	0.0000000	0.0002624
30280POE	PGE3	Other PG&E	PGNV North Valley	0.0000000	
30300TBL MT D	PGE3	Other PG&E	PGNV North Valley	0.0397751	0.0424811
30325PALERMO	PGE3	Other PG&E	PGNV North Valley	0.0068287	0.0072734
31452TRINITY	PGE3	Other PG&E	PGNV North Valley	0.0040275	
31464COTWD PGE	PGE3	Other PG&E	PGNV North Valley	0.0061422	
31468CASCADE	PGE3	Other PG&E	PGNV North Valley	0.0048510	
31482PALERMO	PGE3	Other PG&E	PGNV North Valley	0.0081583	0.0098658
31490BUTTVLLY	PGE3	Other PG&E	PGNV North Valley	0.0054923	
36904MILLWOOD	PGE3	Other PG&E	PGNV North Valley	0.0046849	
37545COTWD WAP	PGE3	Other PG&E	PGNV North Valley	0.0040588	
37555J.F.CARR	PGE3	Other PG&E	PGNV North Valley	0.0000000	
37558KESWICK	PGE3	Other PG&E	PGNV North Valley	0.0154206	
37943RDGPOWER	PGE3	Other PG&E	PGNV North Valley	0.0194556	
30020LINDA	PGE3	Other PG&E	PGSA Sacramento Valley	0.0000000	0.0000000

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30025MAXWELL	PGE3	Other PG&E	PGSA Sacramento Valley	0.0000000	
30030VACA-DIX	PGE3	Other PG&E	PGSA Sacramento Valley	0.0000000	0.0000000
30327COLGATE	PGE3	Other PG&E	PGSA Sacramento Valley	0.0116967	0.0117028
30330RIO OSO	PGE3	Other PG&E	PGSA Sacramento Valley	0.0082888	0.0126000
30337GOLDHILL	PGE3	Other PG&E	PGSA Sacramento Valley	0.0136853	0.0251237
30340RALSTON	PGE3	Other PG&E	PGSA Sacramento Valley	0.0000000	
30345MIDLFORK	PGE3	Other PG&E	PGSA Sacramento Valley	0.0000000	0.0000000
30450CORTINA	PGE3	Other PG&E	PGSA Sacramento Valley	0.0093732	0.0109474
30460VACA-DIX	PGE3	Other PG&E	PGSA Sacramento Valley	0.0156630	0.0938066
30478LAMBIE	PGE3	Other PG&E	PGSA Sacramento Valley	0.0000000	
30480USWP-RUS	PGE3	Other PG&E	PGSA Sacramento Valley	0.0082338	
31950CORTINA	PGE3	Other PG&E	PGSA Sacramento Valley	0.0000261	
32206BOGUE	PGE3	Other PG&E	PGSA Sacramento Valley	0.0084477	0.0090076
32208GLEAF TP	PGE3	Other PG&E	PGSA Sacramento Valley	0.0002073	0.0002216
37524SUTTER	PGE3	Other PG&E	PGSA Sacramento Valley	0.0000000	0.0000000
37546ELVERTAW	PGE3	Other PG&E	PGSA Sacramento Valley	0.0068889	
37548FOLSOM	PGE3	Other PG&E	PGSA Sacramento Valley	0.0000000	0.0000000
37565OLINDAW	PGE3	Other PG&E	PGSA Sacramento Valley	0.0000000	0.0000000
37567ROSEVILL	PGE3	Other PG&E	PGSA Sacramento Valley	0.0358240	0.0383532
30035TRACY	PGE3	Other PG&E	PGSN San Joaquin	0.0000000	0.0000000
30040TESLA	PGE3	Other PG&E	PGSN San Joaquin	0.0000000	0.0013157
30050LOSBANOS	PGE3	Other PG&E	PGSN San Joaquin	0.0000000	0.0000000
30570USWP-RLF	PGE3	Other PG&E	PGSN San Joaquin	0.0062343	
30580ALTM MDW	PGE3	Other PG&E	PGSN San Joaquin	0.0000000	
30670WESTLEY	PGE3	Other PG&E	PGSN San Joaquin	0.0181307	0.0222477
30765LOSBANOS	PGE3	Other PG&E	PGSN San Joaquin	0.0078623	0.0102931
33540TESLA	PGE3	Other PG&E	PGSN San Joaquin	0.0154889	0.0735803
37585TRCY PMP	PGE3	Other PG&E	PGSN San Joaquin	0.0250362	0.0288509
38204PRKR MID	PGE3	Other PG&E	PGSN San Joaquin	0.0412912	0.0495595
38400WALNUT	PGE3	Other PG&E	PGSN San Joaquin	0.0381670	0.0620867
38420TUOLUMN	PGE3	Other PG&E	PGSN San Joaquin	0.0349208	
30482LOCKFORD	PGE3	Other PG&E	PGST Stockton	0.0217037	
30485TIGR CRK	PGE3	Other PG&E	PGST Stockton	0.0006342	
30487ELECTRA	PGE3	Other PG&E	PGST Stockton	0.0018947	0.0076210
30490VLLY SPS	PGE3	Other PG&E	PGST Stockton	0.0140876	
30500BELLOTA	PGE3	Other PG&E	PGST Stockton	0.0132114	0.0791622
30503COLLERV L	PGE3	Other PG&E	PGST Stockton	0.0000000	0.0000000
30505WEBER	PGE3	Other PG&E	PGST Stockton	0.0281078	
30515WARNERVL	PGE3	Other PG&E	PGST Stockton	0.0066019	0.0333423
30624TESLA E	PGE3	Other PG&E	PGST Stockton	0.0131341	0.0423321
33502FROGTOWN	PGE3	Other PG&E	PGST Stockton	0.0059406	
33548TRACY	PGE3	Other PG&E	PGST Stockton	0.0225049	
33549GWFTTRACY	PGE3	Other PG&E	PGST Stockton	0.0098576	
33566CAMANCHE	PGE3	Other PG&E	PGST Stockton	0.0046679	
33900DONNELLS	PGE3	Other PG&E	PGST Stockton	0.0005930	
33916CURTISS	PGE3	Other PG&E	PGST Stockton	0.0075782	

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33932MELONES	PGE3	Other PG&E	PGST Stockton	0.0075915	
33952VALLY HM	PGE3	Other PG&E	PGST Stockton	0.0091963	
36962MOCCASIN	PGE3	Other PG&E	PGST Stockton	0.0000000	0.0134316
37563MELONES	PGE3	Other PG&E	PGST Stockton	0.0011945	
38000LODI	PGE3	Other PG&E	PGST Stockton	0.0246610	
38208COTTLE B	PGE3	Other PG&E	PGST Stockton	0.0030223	
38238HUNTWSTP	PGE3	Other PG&E	PGST Stockton	0.0297747	
31998VACA-DIX	PGE3	Other PG&E	PGVA Vaca-Dixon	0.0553683	
30055GATES	PGE4	Los Padres	PGLP Los Padres	0.0000000	0.0000000
30057DIABLO	PGE4	Los Padres	PGLP Los Padres	0.0459225	0.0469651
30060MIDWAY	PGE4	Los Padres	PGLP Los Padres	0.0409000	
30900GATES	PGE4	Los Padres	PGLP Los Padres	0.0158274	0.0715379
30915MORROBAY	PGE4	Los Padres	PGLP Los Padres	0.0995443	0.1094805
30925DIABLOCN	PGE4	Los Padres	PGLP Los Padres	0.0000000	
30930MESA PGE	PGE4	Los Padres	PGLP Los Padres	0.1256266	0.1294805
30935ARCO	PGE4	Los Padres	PGLP Los Padres	0.0334154	
30945KERN PP	PGE4	Los Padres	PGLP Los Padres	0.1000869	
30970MIDWAY	PGE4	Los Padres	PGLP Los Padres	0.0164990	0.6425359
34378GATES	PGE4	Los Padres	PGLP Los Padres	0.0475333	
34712FAMOSO	PGE4	Los Padres	PGLP Los Padres	0.0272416	
34718KERN OIL	PGE4	Los Padres	PGLP Los Padres	0.0505045	
34736MAGUNDEN	PGE4	Los Padres	PGLP Los Padres	0.0442377	
34752KERN PWR	PGE4	Los Padres	PGLP Los Padres	0.1800282	
34774MIDWAY	PGE4	Los Padres	PGLP Los Padres	0.0711377	
34776TAFT	PGE4	Los Padres	PGLP Los Padres	0.0387905	
34779MIDSUN	PGE4	Los Padres	PGLP Los Padres	0.0115869	
34792KERNRDGE	PGE4	Los Padres	PGLP Los Padres	0.0382270	
34814FRITO LY	PGE4	Los Padres	PGLP Los Padres	0.0128657	
24006ALMITOSE	SCE	L.A./ Orange	SCE Southwest	0.0406002	0.0574478
24016BARRE	SCE	L.A./ Orange	SCE Southwest	0.1460654	0.2068296
24029DELAMO	SCE	L.A./ Orange	SCE Southwest	0.1121368	0.1433608
24044ELLIS	SCE	L.A./ Orange	SCE Southwest	0.1337167	0.2901954
24069HUNTGBCH	SCE	L.A./ Orange	SCE Southwest	0.0000000	0.0000000
24072JOHANNA	SCE	L.A./ Orange	SCE Southwest	0.0909820	
24131S.ONOFRE	SCE	L.A./ Orange	SCE Southwest	0.0468042	0.1065111
24134SANTIAGO	SCE	L.A./ Orange	SCE Southwest	0.1485371	
24137SERRANO	SCE	L.A./ Orange	SCE Southwest	0.0000000	0.1956553
24138SERRANO	SCE	L.A./ Orange	SCE Southwest	0.0000000	0.0000000
24154VILLA PK	SCE	L.A./ Orange	SCE Southwest	0.1604662	
25201LEWIS	SCE	L.A./ Orange	SCE Southwest	0.1206913	
24040EL NIDO	SCE	Other SCE	SCE Southwest	0.0196947	
24049ELSEGNDO	SCE	Other SCE	SCE Southwest	0.0000000	0.0163954
24061HARBOR	SCE	Other SCE	SCE Southwest	0.0000000	
24065HINSON	SCE	Other SCE	SCE Southwest	0.0279094	0.0293359
24074LA FRESA	SCE	Other SCE	SCE Southwest	0.0373364	0.0515325
24076LAGUBELL	SCE	Other SCE	SCE Southwest	0.0368630	0.0570195

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24077LBEACH	SCE	Other SCE	SCE Southwest	0.0000000	
24082LCIENEGA	SCE	Other SCE	SCE Southwest	0.0250927	0.0282614
24084LITEHIPE	SCE	Other SCE	SCE Southwest	0.0257168	0.0270310
24125REDONDO	SCE	Other SCE	SCE Southwest	0.0000000	0.0000000
24198CHEVMAIN	SCE	Other SCE	SCE Southwest	0.0093988	
24021CENTER S	SCE	Other SCE	SCE Core	0.0277493	
24025CHINO	SCE	Other SCE	SCE Core	0.0518333	0.0886037
24036EAGLROCK	SCE	Other SCE	SCE Core	0.0111334	0.0117024
24041ELDORDO	SCE	Other SCE	SCE Core	0.0003353	
24042ELDORDO	SCE	Other SCE	SCE Core	0.0000000	0.0000000
24056ETIWANDA	SCE	Other SCE	SCE Core	0.0343362	0.0698094
24059GOULD	SCE	Other SCE	SCE Core	0.0058744	0.0174539
24085LUGO	SCE	Other SCE	SCE Core	0.0000161	0.0000168
24086LUGO	SCE	Other SCE	SCE Core	0.0000000	0.0000000
24091MESA CAL	SCE	Other SCE	SCE Core	0.0324133	0.0866810
24092MIRALOMA	SCE	Other SCE	SCE Core	0.0000000	0.0166033
24093MIRALOMW	SCE	Other SCE	SCE Core	0.0341278	
24097MOHAVE	SCE	Other SCE	SCE Core	0.0000000	0.0000000
24100LINDA	SCE	Other SCE	SCE Core	0.0198747	
24112PADUA	SCE	Other SCE	SCE Core	0.0348540	
24126RIOHONDO	SCE	Other SCE	SCE Core	0.0377079	
24132SANBRDNO	SCE	Other SCE	SCE Core	0.0302109	0.0317546
24147SYLMAR S	SCE	Other SCE	SCE Core	0.0000000	0.0000000
24151VALLEYSC	SCE	Other SCE	SCE Core	0.0710310	0.0746607
24155VINCENT	SCE	Other SCE	SCE Core	0.0000000	0.0117253
24156VINCENT	SCE	Other SCE	SCE Core	0.0000000	0.0000000
24158WALNUT	SCE	Other SCE	SCE Core	0.0343672	
24801DEVERS	SCE	Other SCE	SCE Core	0.0000000	0.0000000
24804DEVERS	SCE	Other SCE	SCE Core	0.0000000	0.0376559
24901VISTA	SCE	Other SCE	SCE Core	0.0669322	0.0791550
25001GOODRICH	SCE	Other SCE	SCE Core	0.0173082	
24058GOLETA	SCE	Other SCE	SCE Core	0.0151620	0.0159369
24088MANDALAY	SCE	Other SCE	SCE Core	0.0000000	
24099MOORPARK	SCE	Other SCE	SCE Core	0.0372534	0.0391568
24106ORMOND	SCE	Other SCE	SCE Core	0.0000000	
24114PARDEE	SCE	Other SCE	SCE Core	0.0363865	0.0393058
24128S.CLARA	SCE	Other SCE	SCE Core	0.0331099	0.0348015
24087MAGUNDEN	SCE	Other SCE	SCE North	0.0066293	0.0122710
24101OMAR	SCE	Other SCE	SCE North	0.0000000	0.0000000
24115PASTORIA	SCE	Other SCE	SCE North	0.0000000	0.0023607
24153VESTAL	SCE	Other SCE	SCE North	0.0100242	
24217WARNETAP	SCE	Other SCE	SCE North	0.0000000	
24235RECTOR	SCE	Other SCE	SCE North	0.0356938	0.0428564
24301BIG CRK1	SCE	Other SCE	SCE North	0.0000000	
24302BIG CRK2	SCE	Other SCE	SCE North	0.0000000	
24303BIG CRK3	SCE	Other SCE	SCE North	0.0024426	0.0047771

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24304BIG CRK4	SCE	Other SCE	SCE North	0.0021888	
24305BIG CRK8	SCE	Other SCE	SCE North	0.0000000	
24401ANTELOPE	SCE	Other SCE	SCE North	0.0309870	0.0326656
24403BAILEY	SCE	Other SCE	SCE North	0.0033442	
24350HIDESERT	SCE	Other SCE	SCHD High Desert	0.0000000	
24601VICTOR	SCE	Other SCE	SCHD High Desert	0.0153351	0.0175433
24701KRAMER	SCE	Other SCE	SCHD High Desert	0.0050563	0.0090261
24716COLWATER	SCE	Other SCE	SCHD High Desert	0.0040330	
24717COLWATER	SCE	Other SCE	SCHD High Desert	0.0000000	0.0000000
24722CONTROL	SCE	Other SCE	SCHD High Desert	0.0005543	
24723CONTROL	SCE	Other SCE	SCHD High Desert	0.0000000	
24729INYO	SCE	Other SCE	SCHD High Desert	0.0138977	0.0139011
24731INYOKERN	SCE	Other SCE	SCHD High Desert	0.0051063	
24017BLYTHESC	SCE	Other SCE	SCLD Low Desert	0.0031982	
24019CAMINO	SCE	Other SCE	SCLD Low Desert	0.0000713	
24805DEVERS	SCE	Other SCE	SCLD Low Desert	0.0214311	
24806MIRAGE	SCE	Other SCE	SCLD Low Desert	0.0062459	
24815GARNET	SCE	Other SCE	SCLD Low Desert	0.0116831	
25402GENE	SCE	Other SCE	SCLD Low Desert	0.0000000	
25634BUCKWND	SCE	Other SCE	SCLD Low Desert	0.0080486	
22228ENCINA	SDG&E	SDG&E	SDGE San Diego	0.0979613	
22232ENCINA	SDG&E	SDG&E	SDGE San Diego	0.0000000	0.0000000
22260ESCNDIDO	SDG&E	SDG&E	SDGE San Diego	0.1363538	0.1801839
22412LOSCOCHS	SDG&E	SDG&E	SDGE San Diego	0.0724011	
22424MAINST50	SDG&E	SDG&E	SDGE San Diego	0.0390552	
22460MIGUEL	SDG&E	SDG&E	SDGE San Diego	0.0181066	
22464MIGUEL	SDG&E	SDG&E	SDGE San Diego	0.0898300	0.1302036
22500MISSION	SDG&E	SDG&E	SDGE San Diego	0.0719707	
22504MISSION	SDG&E	SDG&E	SDGE San Diego	0.0037120	0.1112138
22580NORTHCTY	SDG&E	SDG&E	SDGE San Diego	0.0615616	
22596OLD TOWN	SDG&E	SDG&E	SDGE San Diego	0.0857838	0.0917004
22652PENSQTOS	SDG&E	SDG&E	SDGE San Diego	0.0694423	0.1081072
22716SANLUSRY	SDG&E	SDG&E	SDGE San Diego	0.0655437	0.0869349
22772SOUTHBAY	SDG&E	SDG&E	SDGE San Diego	0.0914737	0.1948307
22844TALEGA	SDG&E	SDG&E	SDGE San Diego	0.0968041	0.0968256
22356IMPRLVLY	SDG&E	SDG&E	SDMIV Imperial Valley	0.0000000	0.0000000
22360IMPRLVLY	SDG&E	SDG&E	SDMIV Imperial Valley	0.0000000	0.0000000
22468MIGUEL	SDG&E	SDG&E	SDMIV Imperial Valley	0.0000000	0.0000000
22536N.GILA	SDG&E	SDG&E	SDMIV Imperial Valley	0.0000000	0.0000000
38610DELTAPMP	PGE3	CWR4	PGEB East Bay	0.5000000	0.5000000
38615DS AMIGO	PGE3	CWR4	PGSN San Joaquin	0.5000000	0.5000000
30994WHEELER	PGE4	CWR5	PGLP Los Padres	1.0000000	
25613EDMONSTN	SCE	CWR6	SCE North	1.0000000	
25406J.HINDS	SCE	MWD	SCLD Low Desert	1.0000000	1.0000000
14001FOURCORN	AZ2		FCORNR_5_PSUEDO	N/A	N/A
14002MOENKOPI	AZ2		ELDORD_5_MOENKP	N/A	N/A

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15021PALOVRDE	AZ3		PVERDE_5_DEVERS	N/A	N/A
15090HASSYAMP	AZ3		PVERDE_5_NG-PLV	N/A	
84836N.GILA	AZ5		NGILA_5_NG4	N/A	N/A
21007COACHELV	II1		DEVERS_2_COCHLA	N/A	N/A
21076RAMON	II1		MIRAGE_2_COCHLA	N/A	
21025ELCENTRO	II2		IVALLY_2_230S	N/A	N/A
26094SYLMARLA	LA1		SYLMAR_2_LDWP	N/A	N/A
26046MCCULLG2	LA2			N/A	
26048MCCULLG5	LA2		ELDORD_5_MCLLGH	N/A	N/A
26136COTTONWD	LA3		INYOS_2_LDWP	N/A	N/A
26105VICTORVL	LA4		LUGO_5_VICTVL	N/A	N/A
14005WESTWING	LA5		LUGO_5_WSTWNG	N/A	
19038MEAD	LA5			N/A	
26003ADELANTO	LA5			N/A	N/A
26041INTERMT	LA5			N/A	
26043INTERMT	LA5		LUGO_5_IPPDC	N/A	N/A
26044MARKETPL	LA5		LUGO_5_MKTPLC	N/A	N/A
26114INTERMTX	LA5			N/A	N/A
64056GONDER	LA5		LUGO_5_GONDER	N/A	
65995MONA	LA5		LUGO_5_MONA	N/A	
19011MEAD N	LC1			N/A	
19012MEAD S	LC1		MEAD_2_WALC	N/A	N/A
19020BLYTHE	LC2		BLYTHE_1_WALC	N/A	N/A
19042PARKER	LC3		PARKR_2_GENE	N/A	N/A
20118ROA-230	MX		IVALLY_2_23050	N/A	
20149TJI-230	MX		TJUANA_2_23040	N/A	N/A
18166LAUGHLIN	NV3		MOHAVE_6_69KV	N/A	N/A
18620MERCHANT	NV4		MRCHNT_2_ELDORD	N/A	N/A
40687MALIN	NW1		MALIN_5_RNDMTN	N/A	
45035CAPTJACK	NW1		CAPJAK_5_OLINDA	N/A	
45087DELTA	NW2		CASCAD_1_CRAGVW	N/A	
26999SYLMARDC	NW3		SYLMAR_2_NOB	N/A	N/A
37005ELVERTAS	SMUD		ELVRTA_2_ELVRTW	N/A	
37010HURLEY S	SMUD		HURLEY_2_WAPA	N/A	
37012LAKE	SMUD		LAKE_2_GOLDHL	N/A	
37016RNCHSECO	SMUD		RANCHO_2_BELOTA	N/A	
37017UNIONVLY	SMUD			N/A	
37018WHITEROK	SMUD			N/A	
64023CAL S PS	SR2		SUMITM_1_SPP	N/A	
64107SUMMIT 1	SR2			N/A	
64108SUMMIT 2	SR2			N/A	
64109SUMMIT 3	SR2			N/A	
64096SLVR PS	SR3		SLVRPK_7_SPP	N/A	