CALIFORNIA ISO

California Independent
System Operator

CONGESTION REVENUE RIGHTS
PRELIMINARY STUDY REPORT

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Congestion Revenue Rights Study Report

1 Executive Summary

At the beginning of 2002 the California Independent System Operation (ISO) embarked on an initiative, the Market Design 2002 initiative or MD02, to redesign the ISO's spot markets and congestion management system.[1] The primary objective of this effort is to improve the ISO's core functions of providing non-discriminatory transmission service, and reliably operating the transmission grid. Toward this end a fundamental element of MD02 has been the redesign of the ISO's original "zonal" congestion management approach. The zonal approach has been problematic since ISO start-up due to its failure to utilize a realistic representation of the transmission grid in the forward (Day Ahead and Hour Ahead) scheduling and congestion management processes. To remedy this flaw the MD02 proposal is centered on the introduction of the Locational Marginal Pricing (LMP) congestion management approach currently used by the eastern ISOs. LMP will utilize a fully detailed and accurate "Full Network Model" (FNM) in the ISO's forward and Real Time markets to ensure that forward schedules do not violate transmission constraints and that transmission allocation and pricing are done in a consistent manner in all ISO markets.

An inherent feature of LMP is the production of locational energy prices at each node of the grid and the use of these nodal prices as the basis for calculating congestion costs between any two grid locations. This represents a major departure from today's method of calculating congestion costs and, as a result, renders today's Firm Transmission Rights (FTR) inappropriate as a congestion hedging instrument. The ISO has therefore proposed as part of the MD02 design, a new congestion hedging instrument called Congestion Revenue Rights (CRRs). The design of CRRs is consistent with the LMP congestion management approach. That is, CRRs provide a financial hedging mechanism to manage the risk of transmission congestion charges that are based on the nodal price differences produced under LMP.

Most parties do not dispute the benefits of using LMP in conjunction with an accurate model of the transmission grid as a congestion management approach. Indeed, the problems of the ISO's original zonal approach are well known, and are becoming more severe as new generation resources come on-line to serve California consumers. At the same time, many parties are concerned about the impact on consumers of the nodal prices produced by LMP, which will be higher in certain transmission-constrained areas

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[1]For complete details on the MD02 proposal refer to the ISO's Amended Comprehensive Market Design Proposal that was filed with the Federal Energy Regulatory Commission (FERC) on July 22, 2003. This filing is available from the ISO's web site at http://www.caiso.com/docs/2002/05/29/200205290858531076.html.

of the grid. Since these areas tend also to be areas of high load, parties are concerned that the nodal prices in these areas may have large cost impacts. The MD02 proposal therefore includes a number of measures to protect consumers from such impacts without compromising the main sources of the benefits of LMP, i.e., use of the FNM for congestion management, and settlement of supply resources at nodal prices. One such measure is the allocation of CRRs to loads in the ISO control area in sufficient quantities to offset their exposure to LMP congestion charges, subject to the results of a simultaneous feasibility test (SFT).[2] A key unknown at this point – and a driving motive for the present CRR Study – is the degree of CRR coverage that will be achievable when subjected to the SFT. The answer to this question will depend on several factors, not the least of which is the content of FERC's order in response to the July 2003 filing.

As described in the ISO's MD02 filings, the ISO proposes to release CRRs first through an allocation process to load-serving entities (LSEs) on behalf of the end-use loads they serve, and second through an auction process to the market in general.[3] This process of allocation and auction was first described in the ISO's original MD02 filings with the FERC on May 1 and June 17, 2002, and was updated in the July 2003 filing. It is important to note that as a result of extensive discussions with stakeholders during the year between the original filings and the July 2003 filing, the ISO made several important changes to the MD02 design that are expected to increase the feasible degree of CRR coverage for consumers and the quantities of CRRs available to the market in general. As discussed further below, however, the Phase 1 CRR Study described in this report reflects the MD02 design as proposed in the original May and June 2002 MD02 filings.

Several Market Participants (MPs) have expressed concerns regarding the use of an LMP model in California, the possibility of energy price spikes in some areas and large LMP differentials as a result of transmission congestion. The ISO believes that a good approach to assessing the potential impact of the LMP model on the California consumers is to determine the extent to which MPs could receive CRRs as a hedge against LMP price differences (i.e., against transmission congestion charges). Thus the genesis of the ISO's CRR Study program is the desire to estimate the extent of CRR coverage that can be allocated to LSEs on behalf of end-use consumers to hedge them against congestion costs. As a first step the CRR Study attempts to establish a conservative bound (based on the assumptions included in the CRR Study) on the amount of available CRRs, based on the original MD02 design proposal as filed in May and June 2002. As noted, the Phase 1 results will be conservative because the amended (July 2003) MD02 proposal introduces design changes that are expected to increase the amount of CRRs available. Subsequent phases of the CRR Study program

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[2] Other measures included in the MD02 proposal to protect consumers from high locational prices are load aggregation for scheduling and settlement, and local market power mitigation. See the July 22, 2003 filing for details.

[3] Moreover, the allocation and auction processes will be held annually to release CRRs of one-year duration and monthly to release CRRs of one-month duration. In each of these processes the ISO will offer both peak and off-peak CRRs. This structure should allow LSEs and other buyers to obtain the set of CRRs that best fits their time-varying needs for hedging congestion exposure. Further refinement of CRR holdings may be achieved through secondary trading, as described in the July 22, 2003 Filing.

will consider the effects of the July 2003 design changes, as well as other scenarios and assumptions that may be useful in developing as complete and accurate an estimate of CRR coverage as possible.

The ISO began a data-gathering effort in June 2002 as part of its first, comprehensive Congestion Revenue Rights study (CRR Study) presented in this report. After many months of effort and several meetings with Participating Transmission Owners (PTOs) and LSEs to determine the scope of the study and the data required to support it, the ISO was able to complete the data collection phase and embark on the execution of the market runs to determine the extent of the CRR coverage for all the LSEs and the other MPs. The required data consists of (1) specification of Existing Transmission Contract (ETC) rights in terms of MW quantities and source (injection) and sink (take-out) nodes; (2) specification of the rights of converted ETCs and new PTOs, again in terms of the same elements; and (3) CRR requests from LSEs based on the 99.5 percent level of their load duration curves and the injection points of their supply resources.[4]

To perform the simultaneous feasibility runs the ISO acquired a commercially available CRR allocation/auction software system capable of providing most of the required functionality to meet the ISO CRR allocation requirements consistent with the ISO's proposed CRR market design as described in the June 17th, 2002 tariff filing with FERC. The software used for the CRR Study is the same software being used by PJM for its CRR auctions.

The time frame chosen for the CRR Study is the year 2005. The year 2005 represents the first year in the future where the configuration of the grid best matches the conditions under which the LMP congestion management approach and CRR design proposed under MD02 are expected to be operational. Specifically, in 2005, significant transmission upgrades are expected to be completed and certain ETCs are expected to expire. These changes were incorporated in the software used for the CRR Study.

Under both the June 2002 and July 2003 CRR proposals, the ISO will offer annual term CRRs and monthly term CRRs. For purposes of the CRR Study, the annual term was taken to be the year 2005 and the monthly term was represented by an analysis of four different months -- March, June, August and November.

The approach utilized for the CRR Study was, for the most part, consistent with the CRR design proposed by the ISO in its June 17, 2002 Tariff filing with the FERC. The approach differs, however, in certain respects from the ISO's July 2003 filing. Most noteworthy is the fact that the present study models ETC rights as CRR Options and therefore removes the full amount of ETC rights from the capacity of the transmission

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[4] Consistent with the ISO's May and June 2002 filings, the maximum quantity of CRRs an LSE could request was set at the quantity of load that would be exceeded in only 0.5 percent of the hours of the year; this level is sometimes referred to as the 99.5 percent level, or "99.5 percent coverage." In addition, because load-serving SCs will schedule and settle loads at large, standardized load aggregation zones in the ISO's markets under MD02, it was not necessary to specify sink nodes for the purposes of this study.

system that can be made available to non-ETC grid users. In contrast, the July 2003 MD02 filing proposes to model ETC rights as CRR Obligations. This is a crucial feature of the 2003 proposal that is expected to increase the availability of CRRs, because treating ETCs as CRR Obligations allows the SFT to evaluate the total simultaneous effect of ETC and non-ETC rights rather than remove ETC rights from the capacity of the network.

Another limiting assumption of the present CRR Study, which was driven by a limitation of the study software, was the modeling of all CRR requests as point-to-point CRRs with no allowance for the Network Service CRRs described in the ISO's MD02 filings. The use of Network Service CRRs should increase the quantities of available CRRs by redistributing source (injection) MW over a LSEs identified source nodes when the initial request is not simultaneously feasible. Without this capability in the study software at this time, CRR requests had to be reduced in MW rather than redistributed. At the same time, there were some modeling assumptions that may have led to greater quantities of CRRs being simultaneously feasible than would be the case under the actual allocation process; in particular: (1) the enforcement of an incomplete set of transmission operating constraints enforcing all applicable constraints may limit the amount of CRRs that can be allocated; and (2) keeping all transmission lines in service during the monthly allocations – taking out transmission that is scheduled to be out of service may limit the amount of CRRs that can be allocated.

Overall, however, the ISO believes that these CRR Study results are conservative. As such they should be interpreted to suggest a lower bound on the CRRs likely to be available for allocation to LSEs upon implementation of MD02.[5] Subsequent phases of the ISO's CRR Study will address the limitations noted above, as well as the MD02 design changes introduced in the July 2003 filing and any FERC orders related to that filing. Through these subsequent phases the ISO intends to develop more accurate estimates of the amounts of CRRs that will be available to LSEs and other market participants.

Based on the preliminary CRR Study methodology, the following steps were implemented sequentially to estimate the amount of CRR coverage that may be afforded to the LSEs:

1. Determine the amount of transmission capacity that will be utilized by ETCs that do not convert to CRRs and remove this amount from the network capacity that can be made available to non-ETC Grid users, this determination was the result of running Market 1;
2. Provide CRR Options to ETC holders that have converted their ETCs to CRRs and to new PTOs that join the ISO; and

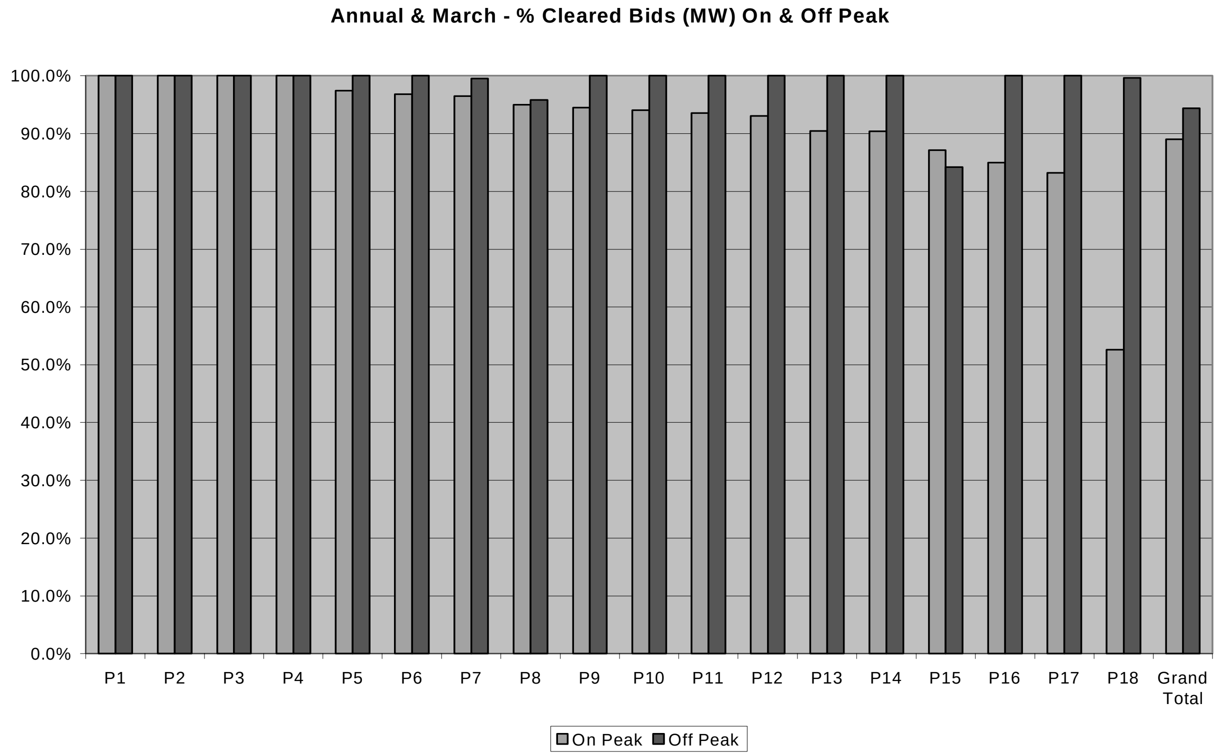
[5] The conservative nature of the CRR Study is reiterated in commentary provided herein by Professor Shmuel Oren of U.C. Berkeley and Professor Robert Wilson of Stanford University.

3. Allocate CRR Obligations to LSEs based on historical and forecasted load calculations.

The ISO conducted a series of 10 market runs, utilizing the acquired CRR allocation/auction software system, to determine the quantity of on and off-peak annual and monthly CRRs that could be simultaneously feasible given the constraints of the ISO controlled grid. Shown below are the tabulated and graphical representations of the results from the annual and monthly allocations to LSEs in each of the market runs[6]. For a summary of the results associated with the markets run for non-converted and converted rights refer to section 6 of this report. Each graph reflects the combined results of the simultaneous feasibility runs for the annual allocation to LSEs plus one of the monthly allocations (i.e., March, June, August or November). The results do not include the MW of capacity set aside for non-converted ETCs or the CRR Options allocated to converted ETCs and new PTOs, which were accounted for prior to conducting the LSE CRR allocation runs. In order to conceal individual LSE results (as requested by some LSEs), the LSE names are represented by symbols "P1", "P2", "P3", etc. on the graphs.

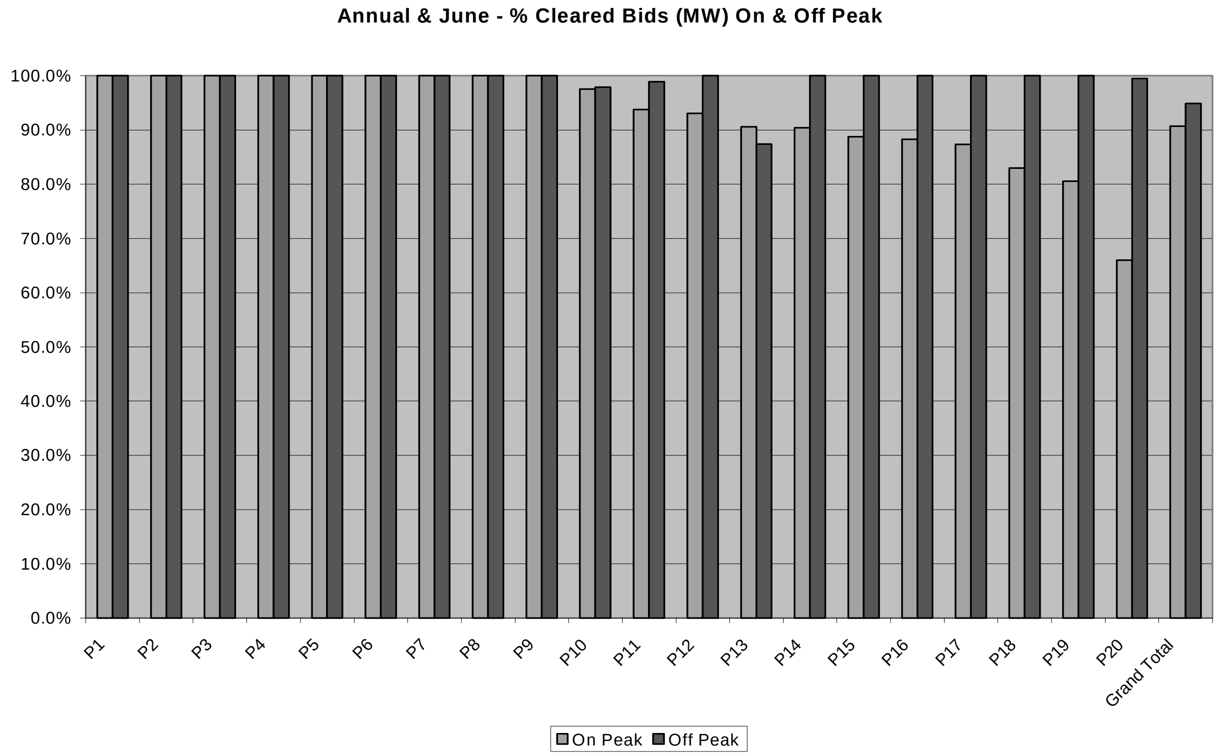
	Peak CRRs		Off-peak CRRs	
LSE Allocation Timeframe	MW Requested	Simultaneously Feasible	MW Requested	Simultaneously Feasible
Annual + March	28,152	25,064	23,892	22,554
Annual + June	36,380	32,995	27,957	26,542
Annual + August	40,611	37,430	30,441	28,372
Annual + November	29,706	26,996	25,750	24,364

[6] Note that these annual and monthly LSE allocation percentages reflect the clerated MW values after the capacity in the network was reduced by the flows associated with converted ETC and non-converted ETC bids.

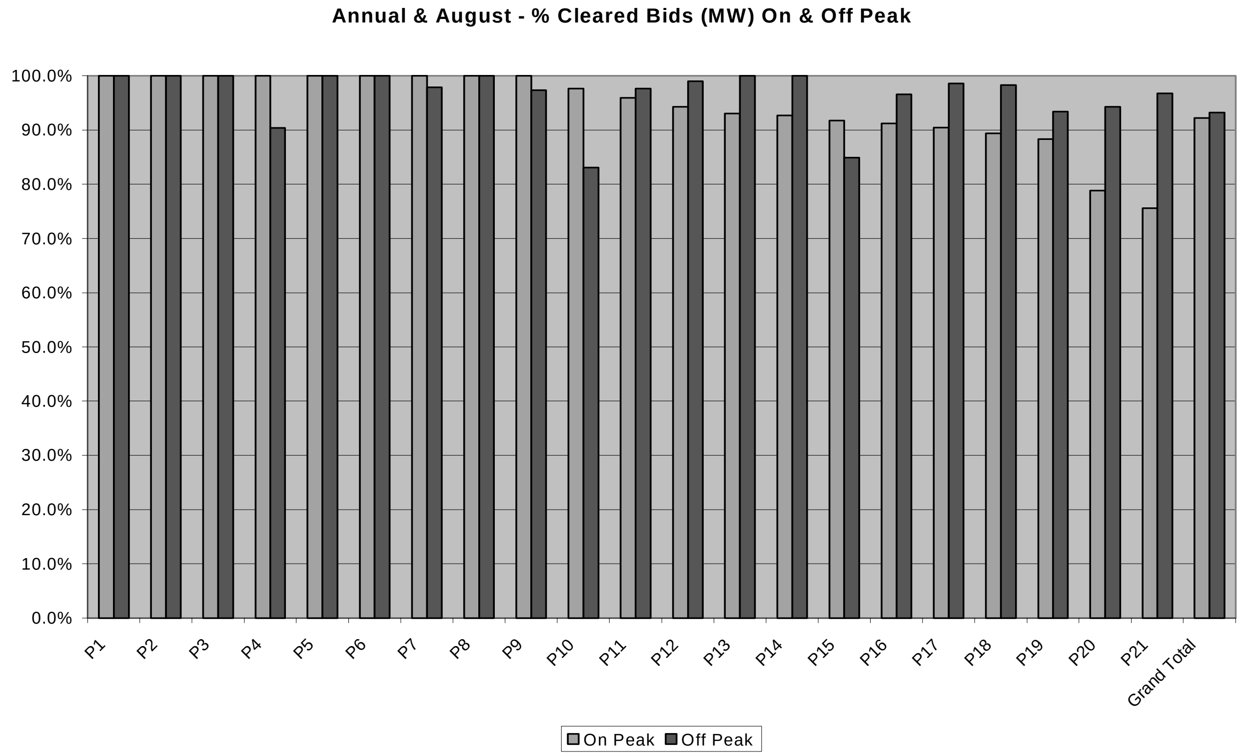


This bar graph reflects the results of the CRR market runs for the annual allocation to LSEs ("P1" through "P18") as well as the LSE monthly allocation for March. There were CRR bids[7] on-peak for a combined total of 28,151 MW with 25,064 MW being cleared. For the off-peak period, there was a combined total of 23,892 MW of bids with 22,553 MW being cleared.

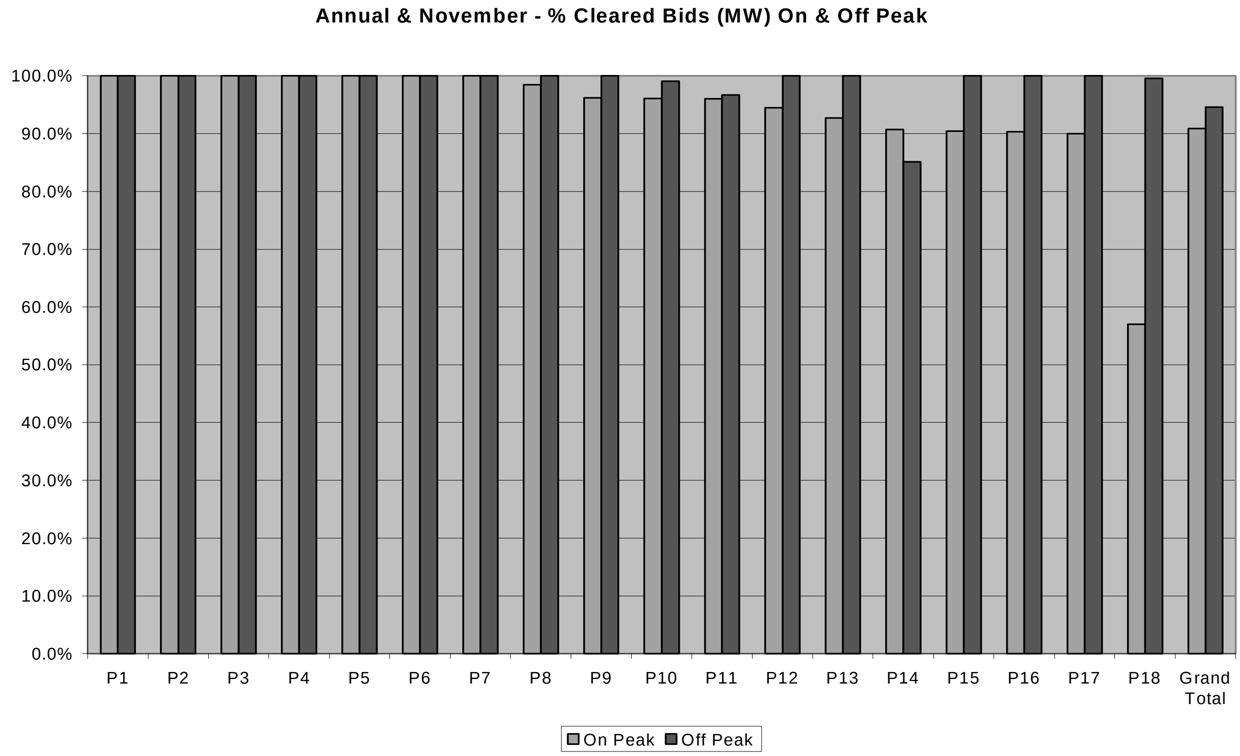
[7] In the context of the CRR Study the term "bid" refers to the allocation request process and the associated source and sink pair that comprises a CRR request.



The bar graph shown above reflects the results of the CRR market runs for the annual allocation to LSEs as well as the LSE monthly allocation for June. CRR bids for on peak had a combined total of 36,380 MW with 32,995 MW being cleared. The off peak numbers show a combined total of 27,956 MW in bids with 26,542 MW being cleared.



The bar graph above shows the results of the CRR market runs for the annual allocation to LSEs as well as the LSE monthly allocation for August. There were on peak CRR bids for a combined total of 40,611 MW with 37,429 MW being cleared. For off peak there was a combined total of 30,440 MW of bids with 28,371 MW being cleared.



This last bar graph reflects the results of the CRR market runs for the annual allocation to LSEs as well as the LSE monthly allocation for November. CRR bids for on peak had a combined total of 29,706 MW with 26,995 MW being cleared. The off peak numbers show a combined total of 25,749 MW in bids with 24,364 MW being cleared.

This Study is based upon a number of assumptions. Some of these assumptions were the result of software and modeling limitations, while others were made to simplify the analysis. The majority of the assumptions for this Study were conservative. That is, they affected the result in a way that suggests a lower allocation of CRRs than will likely be the case. It is expected that the basis for many of these assumptions will be re-examined and refined over time. A discussion of the assumptions follows later in the report.

2 Forward

The present preliminary Congestion Revenue Rights Study (CRR Study) is the first installment of a comprehensive study being undertaken by the California ISO to assess the availability of CRRs to hedge congestion charges under the ISO's Market Design 2002 (MD02) proposal. The data-gathering effort, which began in March 2003, was a time consuming, intensive process. A significant commitment of resources and time was required by both the ISO and Market Participants (MPs) to complete the study. The ISO wishes to thank the MPs for their cooperation and effort in providing the data required for the ISO to complete the CRR Study.

2.1 CRR Requests Non-Binding

Market Participants who provided data to the ISO did so voluntarily and with the understanding that their specific CRR requests could change in the future, both in quantity and location, when more experience is gained and the CRR process is better understood. The ISO wishes to assure MPs that their requests are non-binding and set no precedent with respect to future CRR allocations.

2.2 Data Confidentiality

The ISO recognizes that some data provided to the ISO by MPs is sensitive. In addition, some of the results of the study may also be sensitive. For this reason, the results of the CRR Study have been aggregated for reporting purposes. Individual results will be provided by the ISO directly to the appropriate MPs for their information.

2.3 Data Modeling and Refinement

A major task in conducting the CRR Study was data management. The CRR Study required a vast amount of data from various MPs. Significant steps were taken throughout the CRR Study to properly manage the data and minimize errors that inevitably occur in studies of this magnitude. The ISO will continue to be vigilant in identifying and correcting data errors so that the results of this and any other subsequent studies will be as accurate and meaningful as possible. The ISO expects that data collection, validation, and refinement will be an on-going process for the foreseeable future.

2.4 Interpretation of Study Results

It is important to keep in mind that the CRR Study results presented in this report are the product of many assumptions. Little work has been done at this point to determine the degree of sensitivity these results have with respect to the underlying assumptions. Therefore, the reader is cautioned to consider the results presented here as preliminary and potentially subject to change.

3 Introduction

The California Independent System Operation (ISO), as part of its Market Redesign 2002 project (MD02), plans to implement a new congestion hedging instrument that is consistent in design with the Locational Marginal Pricing (LMP) congestion management approach proposed under MD02. This new instrument, Congestion Revenue Rights (CRR), will be defined on a source-to-sink basis, in contrast to today's path-specific Firm Transmission Rights (FTRs). The ISO will initially offer on and off-peak Point-To-Point (PTP) and Network Service Right obligations of both one-year and one-month duration.

Under the LMP congestion management approach, congestion charges will be based on the differences between the energy prices calculated at each network node. CRRs will be offered to market participants to hedge against these congestion charges. The ISO proposes to allocate CRRs to Load Serving Entities (LSEs)[8] on behalf of the ISO control area loads they serve, and to offer additional CRRs as available to the market in general through an auction process. The ISO's intention in allocating CRRs to LSEs is to cover their exposure to congestion charges as fully as possible, consistent with the results of a simultaneous feasibility test (SFT). The SFT and the processes of allocation and auction were described initially in the ISO's May 1, 2002 Comprehensive Market Design Proposal (Amendment 44) and June 17, 2002 tariff filing with the Federal Energy Regulatory Commission[9]. They are also described in a white paper that can be found on the ISO website[10]. The reader should understand, however, that the ISO has made significant modifications to the MD02 proposal since those filings were made, and should refer to the ISO's July 22, 2003 filing of the Amended Comprehensive Design Proposal for the definitive statement of the ISO's current proposal regarding CRRs and the entire MD02 market design. At the same time, the present Preliminary CRR Study was based on the ISO's original MD02 filings (i.e., May and June 2002) due to the timing of the initiation and conduct of this study.

3.1 Study Objectives

Several MPs have expressed concerns regarding the application of the LMP model in California, specifically with regard to the impacts on congestion charges of higher locational prices in some areas. The ISO recognizes these concerns as well as the importance of estimating and assessing, in advance of the implementation of LMP, the availability of CRRs and their effectiveness in hedging the congestion charges associated with LMP. To this end the ISO initiated the Preliminary LMP Study presented in this report. Specifically, the primary objective of this study was to estimate the extent to which the initial CRR requests submitted by load-serving entities (LSEs) can be fully allocated, given the major market design elements proposed in the ISO's May and June 2002 MD02 filings. In addition, because this Preliminary CRR Study cannot by itself provide all the information needed by the ISO and MPs regarding the

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[8] See Appendix for definition of eligible LSE.

[9] The latter filing, which contained Tariff language implementing the forward-market elements of Amendment 44 (including LMP and CRRs) was never acted on by FERC and was formally withdrawn by the ISO in its July 22, 2003 filing.

[10] This white paper can be found at http://www.caiso.com/docs/2002/10/01/2002100111375026704.pdf.

availability and effectiveness of CRRs, a secondary objective was to test and demonstrate the performance of the CRR study software and other essential study elements such as the network model and the source-to-sink representation of ETC rights.

The software engine used in the CRR Study was developed by Alstom and is identical to the CRR software package currently used at PJM. A brief description of the functionality of ALSTOM's CRR software is contained in Appendix B.

4 CRR Study Overview

The following section provides an overview of the CRR Study. It includes a discussion of the study time frame, study approach, and a general overview of the CRR Study process.

4.1 Study Time Frame

The time frame chosen for the CRR Study is the year 2005. The year 2005 was chosen as it represents the first year in the future where the configuration of the grid best matches the conditions under which the LMP congestion management approach and CRR design proposed under MD02 are expected to be first operational. Specifically, in 2005, significant transmission upgrades are expected to be completed and certain ETCs are expected to expire; these changes were incorporated into the modeling approach used for this study. Additional transmission upgrades are anticipated after 2005, which should provide for greater release of CRRs than this preliminary study indicates.

Under both the current (July 2003) and the original (May-June 2002) CRR proposals, the ISO will offer annual term CRRs and monthly term CRRs. The annual term was taken to be the year 2005 and the monthly term was represented by an analysis of four different months, March, June, August and November.

4.2 Study Approach

The approach utilized for the Preliminary CRR Study was, for the most part, consistent with the methodology proposed by the ISO in its June 17, 2002 MD02 Tariff. The approach differs, however, in certain important respects from the ISO's July 2003 filing. Most significant is the fact that this study models ETC rights as CRR Options and therefore removes from the transmission system the amount of capacity represented by ETC rights. In contrast the July 2003 filing proposes to model ETC rights as CRR Obligations. This is a crucial feature of the July 2003 proposal that is expected to increase the availability of CRRs, because treating ETCs as CRR Obligations allows the SFT to evaluate the total simultaneous effect of ETC rights and CRRs rather than remove ETC rights from the capacity of the network.

The key differences between the CRR Study modeling and the June 17, 2002 Tariff FERC Filing are the following.

1. Network Service Rights, as proposed in the June 2002 Tariff filing and retained in the July 2003 amended filing, are not considered in this study because the Alstom software does not currently support this feature. Network Service Rights will be part of the ISO's actual implementation of CRRs and should allow for a greater release of CRRs than indicated by the present study. The reason for such an increase in CRRs is the ability of the software, when the initial CRR requests are not simultaneously feasible, to re-distribute the total request MW over the requested injection points to achieve feasibility, rather than having simply to reduce the total quantity of CRRs allocated.

2. In the current MD02 proposal there are only three load aggregation areas on which Market Participants will schedule load (except for load under non-converted ETCs which will be scheduled nodally). In this CRR Study, more than three load aggregation areas were utilized. These areas are described later in this report.

4.3 Overview of CRR Study Process

Based on the proposed methodology, the following steps were implemented in sequence in this study to determine the amount of coverage afforded to the various MPs:

1. Determine the amount of transmission capacity that will be utilized by ETCs that do not convert to CRRs, and remove this amount from the network capacity that can be made available to non-ETC grid users;

2. Provide CRR Options to ETCs that convert to CRRs and to new PTOs that join the ISO[11]; and

3. Allocate CRR Obligations to Load Serving Entities (LSEs) based on historical and forecasted load data.

At each step the ISO ran a simultaneous feasibility assessment on the relevant set of desired rights, after fixing the allocation of rights that resulted from the previous steps. The same sequence of steps was followed for both the annual and monthly CRR offerings. Below we describe these steps in greater detail.

4.3.1 Transmission Capacity Needed to Honor Non-Converted ETCs

The purpose of this step was to determine the amount of transmission capacity that must be withheld from the network to honor non-converted ETCs before the CRR allocation and auction processes take place. This will enable the ISO to release CRR quantities that are simultaneously feasible given the need to fully honor ETC rights in the daily scheduling processes. The ISO determined the transmission capacity for non-converted ETCs based on historical reservation patterns on contract paths and specific sources and sinks provided by the ETC rights holders. The ISO then applied these

[11] Although new PTOs and ETC rights holders who convert will be given a choice of CRR Options or Obligations, for this study the ISO made the conservative assumption that such CRRs will be Options.

ETCs as injections and withdrawals on a Full Network Model (FNM) that represents the ISO controlled transmission grid in California. Upon application of these ETC injections and withdrawals, the ISO performed a simultaneous feasibility assessment of the flow patterns of all non-converted ETCs to determine the collective impact of these ETCs on the capacity of the grid. In the event that all ETC reservation patterns were not simultaneously feasible, the CRR software performed pro-rata curtailments to achieve simultaneous feasibility.

In performing the simultaneous feasibility test for this step, the ISO assumed that all ETCs are Options rather than Obligations, consistent with the way ETC rights are specified in the contracts. Since ETCs were treated as Options, the effect of this step was to reduce the transfer capacity of the grid by the amount of flow created by the ETC injections and withdrawals.

4.3.2 Allocation of CRRs to New Participating TOs

With the capacity utilized by the non-converted ETCs removed from the network capacity, the ISO then applied to the FNM, as points of injection and withdrawal, the previously converted ETCs. The assignment of the injection and withdrawal points for the converted ETCs were based upon language in their respective Transmission Control Agreements and discussions with each of the new Participating TOs.

In performing the simultaneous feasibility for this step, the ISO assumed that all converted ETCs are Options rather than Obligations. Since converted ETCs were treated as Options, the effect of this step was to reduce the transfer capacity of the grid by the amount of flow created by the converted ETC injections and withdrawals.

4.3.3 Allocation of CRR Obligations to Load Serving Entities (LSEs).

With the capacity utilized by the converted and non-converted ETCs removed from the network capacity, the ISO, then, applied to the FNM, as points of injection and withdrawal, the requested CRR amounts provided by the LSEs. The ISO then ran an Obligations-type simultaneous feasibility test on the LSE requests. In the event that all the CRR requests were not simultaneously feasible, the auction software curtailed LSE CRR requests according to a predetermined methodology[12].

5 CRR Study Process Steps

The steps taken in the CRR Study process can be grouped into the following four categories:

1. Preparing network model related data;
2. Gathering and modeling Point-to-Point ETC and CRR data;
3. Preparing the mapping from the Point-to-Point ETC and CRR data to the network model; and

[12] Note that for annual previously converted ETCs and for annual LSE requests, a single SFT was done for both at the same time. The reason for this is explained later in this Report.

4. Performing the allocations by conducting market runs in accordance with the process outlined in the June 17, 2002 filed Tariff, and described in this report.

The first two steps were independent of each other, but the third step could not be completed until the first two steps were completed. The final step (i.e., the CRR allocations) could not be started until the first 3 steps were completed.

A detailed description of these 4 steps is provided below.

5.1 Preparing Full Network Model (FNM) Data

The preparation of the full network model consisted of preparing a base case (i.e., a description of the power system) to be utilized by the CRR allocation/auction system for the CRR Study. The preparation of the FNM also included the identification of the operating constraints to be enforced during the allocation simulations, consistent with actual operation of the system, and the determination of the operating transfer capability (OTC) values to be used for enforcing these constraints.

5.1.1 Base Case

The FNM used in the CRR study is based on the same model used in Phase II of the on-going LMP studies, but augmented with 9 transmission upgrades expected to be operational by 2005[13]. The FNM is a passive DC model with an external equivalent and is based on an October 2002 ISO operational model. It contains 3,268 buses and 4,699 branches (this includes internal branches and transformers plus the external lines). In this model, all lines were assumed to be in service. The October 2002 operational model is the model that the ISO's Operations Engineering Department (OE) was using during the October 2002 period for studies in support of real-time grid operations and the forward markets. The models used by OE and the Transmission Planning Department actually model the entire WECC wide power system and consists of about 15,000 buses.

The following steps were taken to derive the model used in the CRR study;

1. Start with the OE October 2002 base case:

2. Prepare an external equivalent;

3. Remove all resistances and all other shunt devices from the model to create the DC network representation;

4. Identify the set of boundary buses[14] to be retained;

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[13] This transmission augmentation aligned the model with the CRR Study period. This Phase II LMP study was released by the ISO in the winter of 2002 and is available on the ISO web site at http://www.caiso.com/docs/2003/02/05/2003020513210610375.pdf

[14] The boundary buses picked were the current inter-tie scheduling points used in the forward market. The scheduling points are actually points that are electrically right outside of the control area.

5. Use a Gaussian elimination technique[15] to reduce the external system while retaining the boundary buses. This will result in an external system that only consists of the boundary buses. This technique will not modify any of the internal control area branch or transformer characteristics; and

6. Modify the system with the transmission upgrades.

The FNM used in LMP Study Phase II was chosen because this model already had the external equivalent created and thus could be readily utilized for the CRR Study. Additionally, the work performed in LMP Study Phase II also identified and modeled a set of interfaces based on this October 2002 model. As noted, this FNM was augmented with 9 transmission upgrades expected to be in operation on or before the start of the study period (i.e., January 1, 2005). These upgrades are all on the bulk system (230 kV and 500 kV) or on an existing Inter-zonal interface and have been approved by the ISO. A brief description of these upgrades is given below. A more detailed description of each upgrade is provided in the Appendix along with the new operational limits that resulted from these transmission upgrades.

1. North East San Jose Project
2. South of Lugo Project
3. Path 15 Project
4. Ravenswood San Mateo reconductoring Project
5. Imperial Valley 500/230 kV transformer addition and replacement
6. Vincent transformer replacement
7. Metcalf third 500/230 kV transformer addition
8. Midway third 500/230 kV transformer addition
9. Path 26 upgrade

There are many sub-transmission projects scheduled to be completed by the start of 2005. However, it was decided that only the bulk transmission projects listed above needed to be modeled in the CRR Study because they would likely have a significant impact on the quantity of CRRs that could be allocated. An upgrade that was not

[15] In general, the Gaussian elimination technique is referred to as Ward equivalencing. It reduces the number of buses, while retaining the electrical characteristics of the external system with respect to these buses. At the same time the technique will also create pseudo injections at the retained buses to model load and generation that existed within the external system. However, in the case of the FNM for the CRR system, there is no generation nor load modeled anywhere within the network, thus the naming of the network as a passive DC network. The CRR sources and sinks, via the ETCs, the converted Rights sources and sinks and the LSE CRR sources and sinks, will represent the active components and will be applied to the passive DC network during the actual allocation processes.

modeled in the October 2002 base case, but is actually currently operational, is the Blythe upgrade[16] [17].

5.1.2 Constraints

As previously noted, there is a simultaneous feasibility test performed during each step of the allocation process. The simultaneous feasibility test consists of checking flows on branches or groups of branches against limits, where these flows are created by the ETC or CRR source and sink pairs (either Option or Obligation injections and withdrawals). For purposes of the CRR Study, thermal constraints[18] and interface constraints[19] were enforced[20].

As noted in the list of enforced interface constraints given in the Appendix, all the current Inter-Zonal interface constraints were enforced. This set includes the two internal paths of Path 15 and Path 26, as well as, all interconnections to adjacent control areas. In addition, the following six interface internal constraints were enforced:

- Humboldt (an existing inactive Inter-Zonal interface);
- San Francisco (an existing inactive Inter-Zonal interface);
- Greater Bay Area;
- San Diego;
- North Bay; and
- Fresno.

These interfaces are consistent with those additional constraints (the current active Inter-Zonal interfaces) that were used in the LMP Phase II study.

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16 Note that the ISO did not receive any requests to use Blythe as a source to serve load, although it is anticipated that this will not be the case in future CRR requests. The Blythe WECC Path 59 upgrade will be modeled in the future when the ISO is able to review and fully assess all issues associated with this transmission upgrade.

17 This upgrade was made by a third party transmission provider (i.e., Blythe Energy) and consisted of replacing a 72 MVA transformer with a 280 MVA transformer and uprating the Blythe – Eagle Mountain 161 kV line to 168 MVA. This upgrade increased the WECC path 59 OTC in the inbound direction.

18 Thermal constraints include the normal operating thermal limits for each branch.

19 An interface is a group of one or more branches defined by the ISO Operations Engineering Department as an important constraint that must be monitored and whose combined flow on each line and transformer (in a specified direction) must be less than an operation limit to ensure reliability. The interface constraints, and their corresponding OTC values that were used in the model, can be found in the Interface Names and Limits table in Appendix A.

20 Based on NERC, WECC and ISO control area operating procedures, during normal operation, the flows on transmission facilities such as lines and transformers shall not exceed their normal ratings (limit). This correlates to the use of the thermal constraints at their normal ratings. During a contingency, the procedures, in short, dictate that all flows be within emergency ratings, voltages remain within certain ranges, and system stability is maintained. The limits associated with the interface constraints reflect the conformance to these contingency related procedures.

Values of the OTCs for the thermal limits were taken from the base case normal ratings. The OTC values for the current Inter-Zonal interfaces were based on discussions with Operating Engineers and Transmission Planning personnel along with 2002 historical OTC information[21]. The OTC values for the six additional interfaces were the same as those used in the LMP phase II study[22].

It is important to remember that the constraints modeled in the CRR study should be consistent with those constraints enforced during the forward market to help ensure revenue adequacy. In other words, it is not appropriate to relax certain constraints in the CRR allocation and auction process that would be enforced in the forward market. If this were to happen then the payout to the CRR holders could potentially exceed the income from the forward market congestion management as more CRR MWs could be allocated and auctioned off than the amount of MWs that could be scheduled in the forward market.

The ISO intends to continue working to develop additional constraints to be modeled in the CRR auction in order to better align the constraints that will be modeled in the forward market with the constraints that need to be enforced during the CRR allocation/auction process. A group of ISO operating engineers and transmission planners has been formed to analyze and model additional constraints that need to be included in the CRR allocation/auction process.

5.2 Gathering and Modeling Point-to-Point ETCs and CRRs

The second step of the CRR study process was to gather the needed Point-to-Point ETC and CRR data. As noted above, there were three distinct sets of data involved in this step:

- Existing transmission contract rights (ETCs);
- Converted existing transmission rights (converted ETCs); and
- CRR requests from LSEs.

This section provides the details of how each of the three data sets were gathered and processed. Also included is a description of some of the difficulties encountered by the ISO and the MPs involved in this process that contributed to delays in the original study timeline.

[21] Note that in the LMP Phase II study, simulations were hourly and thus hourly historical Inter-Zonal OTCs were used. Since the CRR study simulations are not hourly, but pertain to a much broader time frame, the OTC values from the LMP Phase II could not directly be used.

[22] The value of the San Diego interface OTC for the “into” San Diego direction was 2450 MW in the CRR studies. This value should have been 2850 MW, which is the increased import capability due to recent incremental upgrades. This value of 2850 MW will be used in subsequent simulations.

5.2.1 Existing Transmission Contracts

5.2.1.1 Data Gathering Process for Existing Transmission Contracts

Existing Transmission Contracts (ETCs) are agreements between Transmission Owners (TO) and other entities for firm use of the TO's transmission system by these entities. These agreements can vary in their terms, but may include:

- A $/MW price for the use of the transmission system;
- The maximum amount of power that can be transferred over the network;
- Specified injection and withdrawal points on the grid;
- Specified network like rights, where the entity can inject power into and withdraw power from a set of known points; and
- Daily and seasonal variation in the amount of power that can be transported over the network.

These agreements can also be part of larger Interconnection Agreements in which the entity may receive other services from the TO, such as generation support. In general, these contracts are used to get out-of-control-area generation to the entities' loads that are embedded within the TO's transmission system.

The ISO currently uses a radial zonal model for congestion management in the forward markets and thus only manages congestion on Branch Groups (these are the current Inter-Zonal interfaces). In turn, for daily scheduling purposes, the ETCs are only modeled and capacity is only reserved on these Branch Groups. For this CRR Study, the ETCs needed to be in a Point-to-Point format[23].

The first step in the ETC gathering process was to contact each of the three Participating Transmission Owners (PG&E, SCE and SDG&E) with a letter indicating that the ISO would be requiring their assistance in gathering the ETC data in a Point-to-Point format. This letter was sent to PTOs in June of 2002. Shortly after the letter was sent, a template was provided to them that included all of the ETCs that the ISO currently uses in its congestion management model. It was also indicated that this list of ETCs might not be complete since it contained only those ETCs that actually flowed over Inter-Zonal interfaces and would not contain ETCs that were internal to the existing three congestion zones.

Over the next several months, the ISO worked with the PTOs to complete the template. Many conference calls and face-to-face meetings took place to discuss the data requirements for filling out the template. The ISO utilized personnel from its Pre-

[23] In general, most of the ETCs were in a Point-to-Point format originally, i.e. prior to the formation of the ISO, and were converted to a Branch Group format for use in the zonal model when the ISO started operations.

Scheduling Department, who had experience with ETCs, to assist in this data gathering process. However, during this data gathering process, many challenges were encountered that caused delays in getting the needed data. These challenges included the following:

- Initial confusion on exactly what this data was going to be used for;

- Concern on the part of PTOs that the submitted Point-to-Point ETC information would be "binding" upon them immediately upon MD02 implementation. (The PTOs were informed that the submitted data was not binding.);

- Some of the ETCs were similar in format to a network like service, and not to a Point-to-Point format as required by the CRR Study. Extracting specific balanced source and sink points for these ETCs proved to be very taxing; and

- The amount of work involved with this process was significant and required the dedication of resources from the PTOs that at times needed to be balanced with the day-to-day work efforts.

5.2.1.2 Modeling of ETCs

After the PTOs provided as much information as possible, the ISO had to make certain assumptions in order to continue with its modeling efforts. These modeling assumptions included the following.

1. It was noted in the original allocation procedure (June 17, 2002 FERC Filing) that the amount of capacity to be reserved for the ETCs would be equal to maximum historical reservation over the historical reference period (i.e., the year 2002). In all cases, except for those ETCs for Path15, the maximum amount of historical reservation was, in fact, equal to the ETC rights. Thus, in most cases, the MW value associated with each source and sink was taken to be the ETC right. (The Path15 ETC reservations were treated differently, as described below.)

2. For certain ETCs, the contractual rights were actually more than the historical load (i.e., the load for which the ETC is used to serve) and in some cases more than the transmission capacity that serves power to this load. In these cases, the MW value of the source/sink pair for purposes of the CRR Study was set equal to the ETC right. Modeling the MW value of the source/sink pair in this manner (i.e., when this value exceeds the line rating) was known to certainly result in ETC curtailment during the SFT.

3. For certain ETCs, the rights from an actual source (i.e., generator or interchange point) were also mirrored in the opposite direction, consistent with the ETC contract. That is, an ETC with a source as a generator or interchange point and a sink point as a load or interchange point, may have a corresponding source/sink pair, with the source as a load and the sink as a

generator. Thus, rights were modeled with a source at the load location (where no actual source exists) and a sink at the generator or interchange point (where no actual load exists). Since the ETCs were modeled as Options, this source/sink reciprocity did not provide counter-flow and net to zero; rather both directions of flow resulted in reductions in network capacity.

4. For certain ETCs, the rights were network like rights. For example, a certain ETC may have rights from two different locations to serve its load, but generally the rights holder will distribute its total rights across the two locations in any given scheduling period, rather than using the full amount of rights from both locations simultaneously. For the present study, however, to ensure that the ISO would always be able to honor such ETC rights fully, we modeled the full amount of rights from both source locations. If these locations were interchange locations, then the full rights were reserved on both branch groups simultaneously. Following the original plan for reserving ETC rights before allocating Converted Rights and LSE requests, both sources were used and the value of the sink was the sum of the rights from both locations (i.e. double the actual MW value of the ETC rights).

5. The California Department of Water Resources had a more complicated ETC arrangement than other ETC holders. Care was taken in modeling these ETCs because they have a major impact on the flows over Path 15 and Path 26. The modeling ensured that the flow of ETC Options in the off-peak period should be primarily in the south to north direction over Path15, consistent with historical flow patterns. Similarly, the flow of ETC Options over Path15 in the on-peak period should be primarily in the north to south direction, consistent with historical flow.

6. To be consistent with the procedures that were noted above, the level of flow over Path 15 should be consistent with maximum reserved amounts over the historical reference period. However taking into account all of the ETCs (especially including the CDWR ETCs) the flow in the north to south direction was above the historical maximum[24]. Thus all ETC source/sink pairs that flowed over Path15 were scaled to the historical maximum. Note that the historical maximum reservation in the north to south direction was 1250 MW and this is based on an OTC of 1275 MW.

7. As noted above, the ETCs were modeled as stated in the contract and as interpreted by the PTOs. Whereas the sinks for the converted rights (i.e., Previously Converted ETCs) and the LSE requests were limited to the large load aggregations defined by the CAISO, the ETC sinks were not generally modeled at an aggregate level. In general, the ETC sinks are modeled on a

24 Note that PG&E is the path manager for reserving capacity associated with ETCs on Path 15 because in total, Path 15 is over subscribed in the north to south direction. Each day before the Day-Ahead Market closes, PG&E provides updated reservation levels to the CAISO and these reservation levels are always equal to or below the OTC value that the CAISO intends to use in the Day-Ahead congestion management market.

nodal level, with certain exceptions. For the cases where the ETC holder is a municipality, city or county, then a load aggregation was actually created for this ETC sink that was on the level of current CAISO load groups[25]. As a final note with respect to ETCs, some ETCs will expire prior to the 2005 study period and thus were not modeled in the CRR Study.

5.2.2 CRR Requests From Previously Converted ETC Right Holders

The data gathering process was a time intensive process, both for the ISO as well as the new Participating Transmission Owners (PTOs). These new PTOs include the Cities of Anaheim, Azusa, Banning, Riverside and Vernon. Several conference calls were held with these new PTOs and several data iterations occurred as we worked through the issues involved with taking the Previously Converted Rights and moving them into the format needed for P-T-P CRRs.

The new PTOs currently hold FTRs given to them in exchange for their respective transmission rights turned over to the ISO. These FTRs are based on the current three-zone and branch group model and thus needed to be converted to PTP CRR Options. In addition, when the new PTOs had their rights converted to FTRs, there were some rights that could not be accurately modeled due to the radial nature of the ISO market model. For purposes of the CRR Study, the new PTOs were given the choice of retaining all converted rights, as defined in their respective Transmission Control Agreements (TCAs), or retaining a portion of those rights and allowing the balance of their load to be allocated CRR Obligations in the same manner and with the same priority as all other Load Serving Entities (LSEs)[26].

5.2.3 CRR Requests From LSEs

5.2.3.1 Background

The data gathering process for CRR requests from LSEs was also very time consuming. A data request related to the CRR Study was sent to LSEs in late summer of 2002. However, due to a general lack of clarity about the specifics of the LMP implementation and point-to-point CRRs, the LSEs were unable to provide the requested data. The ISO then entered into extensive discussions with the LSEs to define the scope, objectives, and methodology of the CRR Study. This process lasted several months. In addition, the ISO and LSEs participated in the LMP/CRR Working Group sessions where the concepts surrounding LMP and CRRs were discussed and debated. This process lasted until the end of November 2002. During December 2002

25 As will be noted in the section on load disaggregation, all LSE sinks were disaggregated into aggregations on the load group level. These are the aggregations that were used for some of the ETCs.

26 The reason for this was to more accurately reflect how the load of the new PTOs is intended to be served. Some chose to apply this option while others chose to retain all of their converted rights as defined in their respective TCAs.

and the early part of 2003, the ISO CRR team concentrated on procuring a CRR auction system that could be used to conduct the necessary CRR studies[27]. This involved preparing a Request For Proposal, corresponding with vendors on questions and clarifications, reviewing vendor bids, interviewing vendors and finally selecting a preferred vendor.

5.2.3.2 Data Timeline

In late February of 2003 the ISO sent an updated data request to all LSEs who wished to participate in the CRR study. Along with this request was an Excel based data template to be used by the LSEs to fill out and submit all of the appropriate data associated with their CRR request. Several conference calls and meetings to answer questions and receive feedback from LSEs followed this data request. As a result of these discussions, the data template was revised and sent out for a third time. A total of 18 LSEs responded by completing the standardized data template (See Appendix A for a list of LSEs that provided data)[28].

5.2.3.3 Historical and Forecasted Load Information

The data template required LSEs to input one year's worth of hourly historical load data for the year 2002, a load forecast for the months of March, June, August and November 2005, and the total amount of ETC coverage that they had for their load[29]. The ISO then calculated (using a macro function built into the template) the maximum quantity (i.e., Upper Bound) of annual term and monthly term CRRs that could be requested for the On-peak and Off-peak periods (See Appendix for a description of the Upper Bound calculation). LSEs then requested specific CRRs, up to their Upper Bound limit, by indicating in the template the particular source, sink, and MW quantities desired for

[27] For the start of the LMP market, CRRs would need to be allocated and auctioned several weeks before the actual start of this market and as such a longer lead-time was needed to start the procurement of a production CRR system.

[28] Included in this list of LSEs are several Direct Access providers that were able to participate in the CRR Study. Since the ISO interacts mainly with Scheduling Coordinators (SCs) our focus was to communicate to all SCs that schedule load and have them in turn communicate with their respective clients. Unfortunately, we weren't able to reach all LSEs but with this initial study we were able to receive CRR requests from entities that represent about 97% of the total load scheduled with the ISO.

29 Please note that historical and forecasted load information provided by LSEs, which served as the basis for CRR allocations, was assumed by the CAISO to be correct. No validation was done. Also, the load forecast criteria used by LSEs was 1-in-2. That is, 50% of the time the forecasted load is expected to be above and 50% of the time below the actual load. Finally, the gross load forecasts used by the LSEs did not include losses.

annual term and monthly term CRRs each for On-peak and Off-peak periods[30]. These requests were used as inputs to the simultaneous feasibility.

5.2.3.4 Standardized Sources and Sinks

A standardized list of sources and sinks were developed for purposes of the CRR Study. LSEs were required to use this standardized list when requesting CRR allocations. This list of sources includes the resource injection points and the inter-tie scheduling points used currently by the ISO for scheduling purposes plus the three Trading Hubs of NP15, SP15 and ZP26. The list of sinks included the four standard load aggregation areas of PGE3, PGE4, SCE1 and SDG1[31]. For non-conforming pump load, three separate standard load aggregation areas were used for the sinks, specifically CDWR5, CDWR6 and CDWR7[32].

Additional source and sink information can be found in Appendix A and by reviewing the data template found on the following ISO Webpage:

http://www.caiso.com/docs/2002/09/09/200209091508045527.html

5.3 Preparing the Mapping From the Point-to-Point ETCs and CRRs to the Network Model

As mentioned above, the LSEs were required to submit source and sink data using a standardized list of source and sink names. The sinks used are large load aggregation areas. In order to perform a simultaneous feasibility test for all the source/sink pairs, the sources and sinks must be broken down to the nodal level. This process is accomplished through the use of load distribution factors (LDFs)[33].

A set of LDFs was created for PGE3, PGE4, SCE1 and SDG1. A set of LDFs was also created for each of the three trading hubs, NP15, ZP26 and SP15. These LDFs were based on the actual load in the October 2002 base case[34].

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[30] The on and off-peak periods utilized for CRR allocations are those established by NERC (see NERC's Inadvertent Interchange Dispute Resolution Process, Error Adjustment Procedures, and On- and Off-Peak Periods). The On-Peak periods include HE 0700 – HE 2200 PST Monday through Saturday. Off-Peak periods include HE 0100 – HE 0600 and HE 2300 – HE 2400 PST Monday through Saturday and HE 0100 – HE 2400 PST on Sundays. Additional Off-Peak days (treated like Sundays) include New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

[31] Under the July 2003 amended MD02 proposal the PGE3 and PGE4 load aggregation zones will be combined into a single PGE zone.

[32] The non-conforming load aggregation areas were utilized by CDWR.

[33] LDFs are scalar values between 0 and 1 that sum to 1.0 over the nodes that comprise a standardized sink. Thus the LDF for any particular node represents that node's fractional share of the total load assigned to the standardized sink.

[34] It is important to note that since the ETC sinks were not modeled on the large load aggregation level, the load associated with ETCs was subtracted from the total load contained in the aggregation areas, then the remaining load was used to calculate the LDFs for the large load aggregation points (PGE3, PGE4, SCE1 and SDG1). The LDFs for the trading hubs were not altered by ETC load as they were based solely on the actual load in the base case.

As previously mentioned, LSEs were required to use the four large load aggregation areas of PGE3, PGE4, SCE1 and SDGE1 as sinks for their loads. However, after the ISO received this information, a decision was made to break each of these load areas into smaller load groups. The purpose for disaggregating the four load aggregation areas into smaller load groups was to alleviate constraint violations encountered during the SFT in a more efficient manner and thus allow a larger number of CRR Obligations to "clear" the market[35]. Thus, in preparation for the market runs, the large load aggregation areas were broken down into the smaller load group level aggregations shown in the Appendix. The LDFs for the load group level aggregation areas were calculated in the same manner as the LDFs for the demand zone level load aggregation points (i.e., using the actual base case load, discounted by ETC load, within a given load group level aggregation area).

After each of the four load aggregation areas were broken down into smaller load groups, fractional bids were created from the original source to each of the corresponding load groups that comprise the demand zone level load aggregation points[36]. The ISO then applied these bids as points of injection and withdrawal on the network and ran the SFT[37]. The resulting cleared bids were subsequently "reassembled" to arrive at the total quantity of cleared bids from the original source to the original load aggregation areas.

5.4 Market Runs

The ISO conducted a series of 10 market runs, utilizing a CRR auction system[38], to estimate the quantity of on and off-peak annual and monthly CRRs that could be allocated to converted ETCs and the LSEs, after setting aside transmission capacity to honor non-converted ETC rights. The software has the capability to run separate on and off-peak markets simultaneously.

Markets 1 and 2 were yearly markets and Markets 3 through 10 were monthly markets (March, June, August and November). It is important to keep in mind that after Markets

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35 Without breaking down the load aggregation areas into load groups, any downward adjustments made to bid injections at the nodal level by the SFT necessary to achieve simultaneous feasibility could translate into major curtailments of CRRs at the higher load aggregation level since the load distribution factor associated with each injection or withdrawal is fixed.

36 For example, a bid with a source at point "A" and a sink at SCE1 was broken into seven smaller bids having its source at point "A" and sink at each of seven load groups that comprise SCE1. The fraction of the total bid that went to each load group was determined by multiplying the total bid MW quantity by the Load Distribution Factor (LDF) that corresponds to the particular Load Group.

37 After the bids were broken down and prior to running the SFT, the ISO disregarded all bids that were less than 0.05 MW in value (the tolerance of the CRR software). This amounted to disregarding bids that represented in total approximately 230 MW.

38 The software utilized for the CRR system was provided by ALSTOM. This software is the same software that has been used by PJM for four years to run its CRR auction. Results produced by the software have been validated by PJM through extensive testing and by using competitor software as a means to compare results. Although the PJM market auctions on and off-peak point-to-point CRR options and obligations, it does not currently utilize Network Service Rights (NSR). So, the software used for the CRR Study does not have the NSR functionality. As a result, Market Participants were limited to requesting on and off-peak PTP CRRs.

1 and 2 were run, the remaining monthly markets for March (Markets 3 and 4), June (Markets 4 and 5), August (Markets 7 and 8) and November (Markets 9 and 10) were independent of one another and could have been run in any order, provided that Market 3 was run before Market 4, Market 5 was run before Market 6, and so on.

Table 1a shows a summary of each market and Table 1b shows a graphical representation of the markets and the order in which they were run. A description of the 10 markets follows.

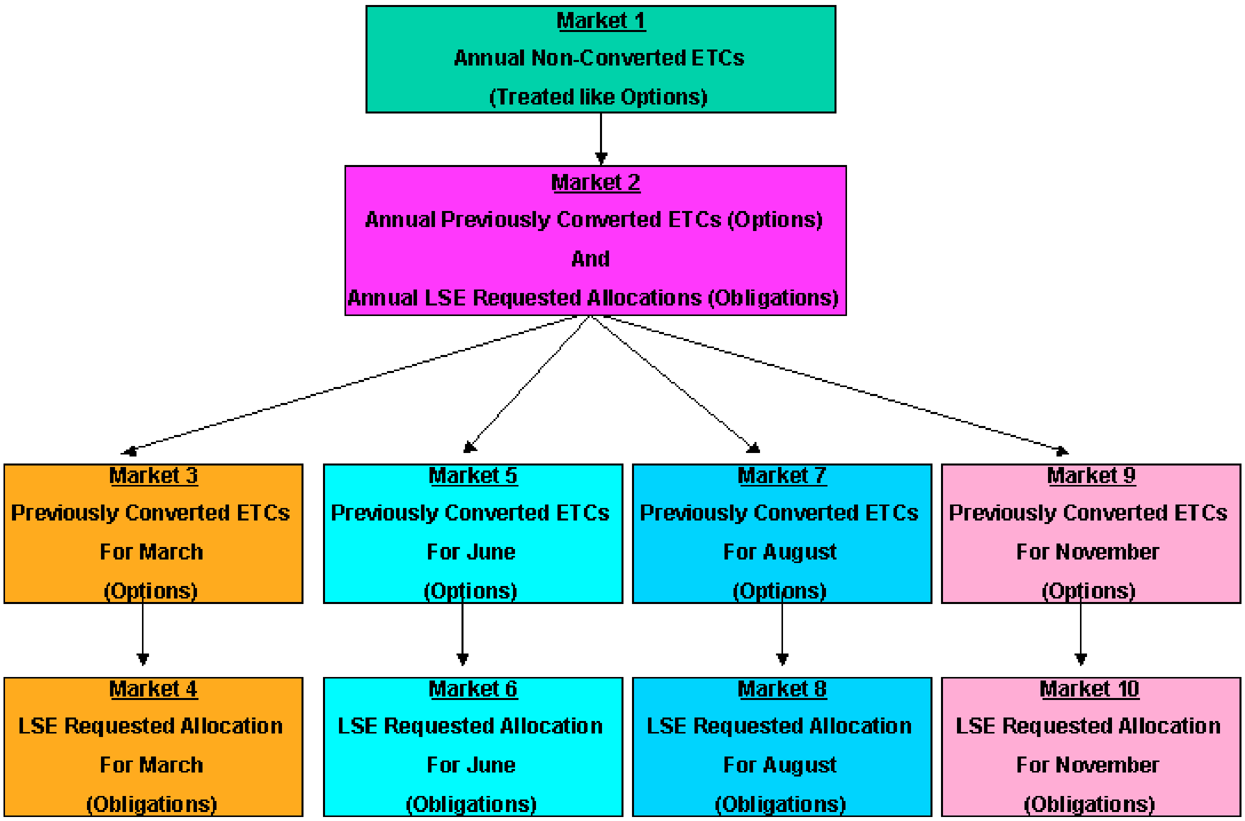
Table 1a

Preliminary CRR Study Market Runs (On and Off-Peak)

Market	Auction	Period Type	Hedge Type	Bid Priority	Percent Network Capacity Utilized
1	Non-Converted ETCs	1 Year	Option	High	100%
2	Previously Converted ETCs And LSE Allocations	1 Year 1 Year	Option Obligations	High Low	75% 75%
3	Previously Converted ETCs	1 Month (March)	Option	High	100%
4	LSE Allocations	1 Month (March)	Obligation	High	100%
5	Previously Converted ETCs	1 Month (June)	Option	High	100%
6	LSE Allocations	1 Month (June)	Obligation	High	100%
7	Previously Converted ETCs	1 Month (August)	Option	High	100%
8	LSE Allocations	1 Month (August)	Obligation	High	100%
9	Previously Converted ETCs	1 Month (November)	Option	High	100%
10	LSE Allocations	1 Month (November)	Obligation	High	100%

Table 1b

Graphic Showing Sequence of Market Runs for CRR Study



5.4.1 Market 1

All non-converted ETCs were modeled simultaneously as PTP injections and withdrawals at the bus level using 100 percent of the network capacity. To ensure that ETCs had the highest priority on the network, they were 1) modeled first before other markets were run; 2) treated as CRR options; and 3) "fixed" in place before the remaining nine markets were run. Since options are not allowed to create counter-flow in the software (for purposes of revenue adequacy), they essentially block capacity equal to the final ETC flows in the network.[39] Once Market 1 was complete, and the final CRR options were fixed in place on the network, the remaining network capacity was scaled down to 75% in preparation for running Market 2[40].

5.4.2 Market 2

This market included both annual previously converted ETC requests and annual LSE requests. Since the previously converted ETC requests have a higher priority on the network compared to LSE requests, they were given a higher bid priority (i.e., higher price) than the bid priority for the LSEs[41]. Additionally, the previously converted ETCs were modeled as options, while the LSE bids were modeled as Obligations (capable of providing counter-flow to the network). Once Market 2 was complete, all injections and withdrawals were fixed in place (like in Market 1) before the remaining eight (monthly) markets were run utilizing the remaining full capacity in the network.

5.4.3 Market 3

Market 3 was the first of four monthly market runs for the previously converted ETCs[42]. This market run covered the month of March. For Market 3, the monthly CRR requests were treated like Options during the SFT and then locked into place before the lower priority March LSE request (Market 4) was run. It is important to note that the CRR requests for this Market (i.e., bid quantities and source and sink locations) are identical

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[39] Allowing options to create counter-flows in the SFT and releasing CRRs on this basis would result in revenue shortfalls in the congestion management markets because the holder of CRR Options has no obligation to pay congestion charges when congestion is in the opposite direction of the CRR.

40 This scaling was done because, under the terms of the ISO's June 2002 MD02 filing only 75 percent of the network capacity may be released for annual CRR allocations. The remaining 25 percent of the network capacity is reserved for monthly CRRs.

[41] Due to certain limitations in the CRR auction software, it was necessary to run both annual previously converted ETCs and annual LSE requests in the same market, rather than in two separate markets, and differentiate them with respect to priority using bid values as the mechanism. This was done in order to correctly scale to 75% the capacity for both the annual previously converted and the annual LSE requests. Use of bid values to model priorities is a standard technique in power flow applications used for transmission rights auctions as well as for ongoing scheduling of the use of the transmission system.

42 The others, which are independent of one another, are Markets 5, 7 and 9.

in Markets 5, 7 and 9[43]. Once Market 3 was complete, and results of the market run were locked, Market 4 was run.

5.4.4 Market 4

This market was run utilizing remaining network capacity after the fixed injections and withdrawals from the three previous markets were in place on the network model. Market 4 was the first of four monthly markets runs for monthly CRR allocations to LSEs[44]. This market, which is a companion to Market 3, covers the month of March. For Market 4, the monthly CRR requests were treated like Obligations during the SFT.

5.4.5 Markets 5 and 6

Once Market 4 was complete, and before running Markets 5 and 6, the fixed injections from Market 3 and Market 4 were removed from the network, leaving only the fixed injections from Market 1 and 2. Markets 5 and 6 for the month of June were run the same as Markets 3 and 4.

5.4.6 Markets 7 and 8

Once Market 6 was complete, and before running Markets 7 and 8, the fixed injections from Market 5 and Market 6 were removed from the network, leaving only the fixed injections from Market 1 and 2. Markets 7 and 8 for the month of August were run the same as Markets 5 and 6.

5.4.7 Markets 9 and 10

Once Market 8 was complete, and before running Markets 9 and 10, the fixed injections from Market 7 and Market 8 were removed from the network, leaving only the fixed injections from Market 1 and 2. Once again, Markets 9 and 10 for the month of November were run the same as Markets 7 and 8.

6 Summary of Results

Results from the 10 market runs are summarized in Tables 2 through 10. Table 2 shows the on and off-peak bid and cleared amounts of non-converted ETCs that were applied to the network (market 1). Tables 3 through 6 provide aggregate results of annual and monthly bid and cleared amounts for previously converted ETCs[45]. Tables 7a through 10b provide aggregated bid and cleared (allocated) amounts of annual and monthly CRRs for LSEs, along with the percentage of CRRs that cleared on and off-peak by LSE. A summary of the cleared CRR MW values by LSE can be found in the Appendix.

43 This is true because the FTR allocations to previously converted ETC right holders are constant year round and thus the requests for previously converted monthly CRRs was assumed to be the same for all months of the study.

[44] The others, which are independent of one another, are Markets 6, 8 and 10.

[45] Please note that the market results for Tables 3 through 6 are the same for all markets since Previously Converted ETCs are constant quantities throughout the year.

A generic summary table for all market runs can be found in the Appendix, along with tables that summarize the binding constraints for each of the ten market runs. Individual bid results will be provided under separate cover to Market Participants who participated in the CRR study.

TABLE 2

Market 1 – Yearly Non-Converted ETC Rights (Options)			
Class Type	Yearly ETC Rights		Percentage of Feasible ETC Rights
	Bid Amount	Cleared Amount	
Off-Peak	11,808	11,227	95%
On-Peak	11,831	11,272	95%

As can be seen from Table 2 above, 95 percent of the non-converted ETCs were found to be simultaneously feasible. It is not surprising that all ETCs did not clear since some of the ETCs modeled actually have rights that exceed the line ratings of the transmission pathways they utilize. In addition, all ETCs were applied to the network simultaneously, which is an unlikely situation in practice. It should be kept in mind as previously stated that, although the ETCs were not found to be 100 percent simultaneously feasible, the ISO intends to fully honor the ETCs in the forward markets and in real time under both the original (2002) and Amended (July 2003) MD02 proposals.

TABLE 3

Market 2 and Market 3 Yearly and Monthly Previously Converted ETC Rights (Options) (in MWs)									
Class Type	(Market 2) Yearly Previously Converted ETC Rights - 2005		Percent Yearly Rights that Cleared	(Market 3) Monthly Previously Converted Rights for March		Percent Monthly Rights that Cleared	(Market 2 and 3) Total Yearly and Monthly Rights		Percent Total Rights that Cleared
	Bid Amount	Cleared Amount		Bid Amount	Cleared Amount		Bid Amount	Cleared Amount	
Off-Peak	963	963	100%	317	317	100%	1,280	1,280	100%
On-Peak	963	963	100%	317	294	93%	1,280	1,257	98%

A review of results in Tables 3, 4, 5 and 6 suggest a very high average clearing of off and on-peak yearly and monthly CRRs. A full 100 percent of the yearly CRRs cleared. For the monthly CRRs 100 percent cleared off-peak and 93 percent cleared on-peak.

TABLE 4

Market 2 and Market 5 Yearly and Monthly Previously Converted Right (Options) (in MWs)									
Class Type	(Market 2) Yearly Previously Converted ETC Rights - 2005		Percent Yearly Rights that Cleared	(Market 5) Monthly Previously Converted Rights for November		Percent Monthly Rights that Cleared	(Market 2 and 5) Total Yearly and Monthly Rights		Percent Total Rights that Cleared
	Bid Amount	Cleared Amount		Bid Amount	Cleared Amount		Bid Amount	Cleared Amount	
Off-Peak	963	963	100%	317	317	100%	1,280	1,280	100%
On-Peak	963	963	100%	317	294	93%	1,280	1,257	98%

TABLE 5

Market 2 and Market 7 Yearly and Monthly Previously Converted Right (Options) (in MWs)									
Class Type	(Market 2) Yearly Previously Converted ETC Rights - 2005		Percent Yearly Rights that Cleared	(Market 7) Monthly Previously Converted Rights for June		Percent Monthly Rights that Cleared	(Market 2 and 7) Total Yearly and Monthly Rights		Percent Total Rights that Cleared
	Bid Amount	Cleared Amount		Bid Amount	Cleared Amount		Bid Amount	Cleared Amount	
Off-Peak	963	963	100%	317	317	100%	1,280	1,280	100%
On-Peak	963	963	100%	317	294	93%	1,280	1,257	98%

TABLE 6

Market 2 and Market 9 Yearly and Monthly Previously Converted Right (Options) (In MWs)									
Class Type	(Market 2) Yearly Previously Converted ETC Rights - 2005		Percent Yearly Rights that Cleared	(Market 9) Monthly Previously Converted Rights for August		Percent Monthly Rights that Cleared	(Market 2 and 9) Total Yearly and Monthly Rights		Percent Total Rights that Cleared
	Bid Amount	Cleared Amount		Bid Amount	Cleared Amount		Bid Amount	Cleared Amount	
Off-Peak	963	963	100%	317	317	100%	1,280	1,280	100%
On-Peak	963	963	100%	317	294	93%	1,280	1,257	98%

TABLE 7a

Market 2 and Market 4 Yearly and Monthly CRR Requests and Allocations to LSEs (in MWs)										
Class Type	(Market 2) Yearly – 2005		Percentage of Yearly Requested Allocation Received	(Market 4) Monthly – March		Percentage of Monthly Requested Allocation Received	(Market 2 and Market 4) Total Yearly and Monthly		Percentage of Total Requested Allocation Received
	Request	Allocation		Request	Allocation		Request	Allocation	
Off-Peak	15,857	14,952	94%	8,036	7,602	95%	23,892	22,554	94%
On-Peak	18,576	17,443	94%	9,576	7,622	80%	28,152	25,064	89%

As can be seen in Table 7a, an average of 94 percent of the yearly CRR LSE requests cleared the SFT process[46]. Also, an average of 95 percent of the monthly off-peak CRR requests for March cleared while 80 percent cleared on-peak. Total average CRR allocations off and on-peak were 94 percent and 89 percent, respectively.

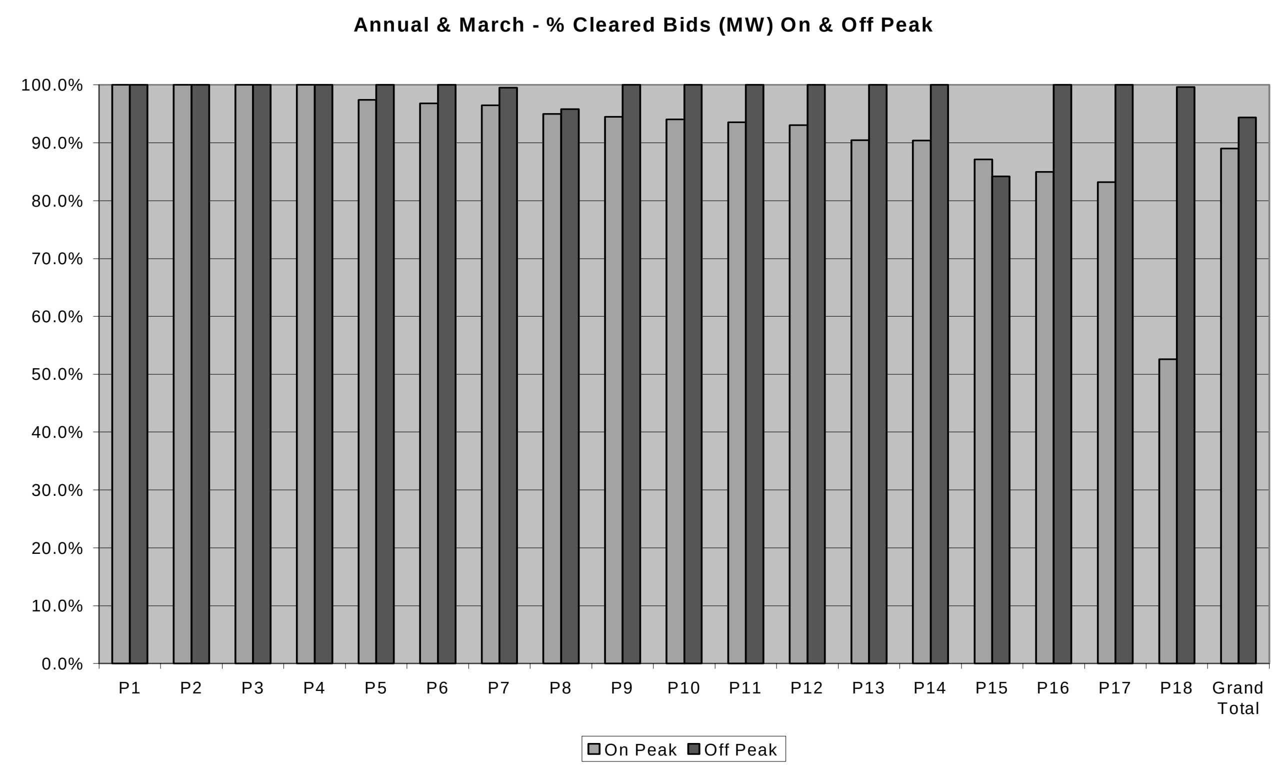

TABLE 7b

[46] Note that results are identical for the yearly CRR LSE allocations, as shown in Tables 8a, 9a and 10a.

The graph in Table 7b above reflects the results of the CRR market runs for the annual allocation to LSEs as well as the LSE monthly allocation for March. There were CRR bids on peak for a combined total of 28,151 MW with 25,064 MW being cleared. For off peak there was a combined total of 23,892 MW of bids with 22,553 MW being cleared.

TABLE 8a

Market 2 and Market 6
Yearly and Monthly CRR Requests and Allocations to LSEs
(in MWs)

	(Market 2) Yearly - 2005		Percentage of Yearly Requested Allocation Received	(Market 6) Monthly - June		Percentage of Monthly Requested Allocation Received	(Market 2 and Market 6) Total Yearly and Monthly		Percentage of Total Requested Allocation Received
Class Type	**Request**	**Allocation**		**Request**	**Allocation**		**Request**	**Allocation**	
Off-Peak	15,857	14,952	94%	12,100	11,590	96%	27,957	26,542	95%
On-Peak	18,576	17,443	94%	17,804	15,553	87%	36,380	32,995	91%

Table 8a results show 96 percent of June CRR requests cleared off-peak and 87 percent cleared on-peak. This resulted in total average clearing of 95 percent off-peak and 91 percent on-peak.

Annual & June - % Cleared Bids (MW) On & Off Peak

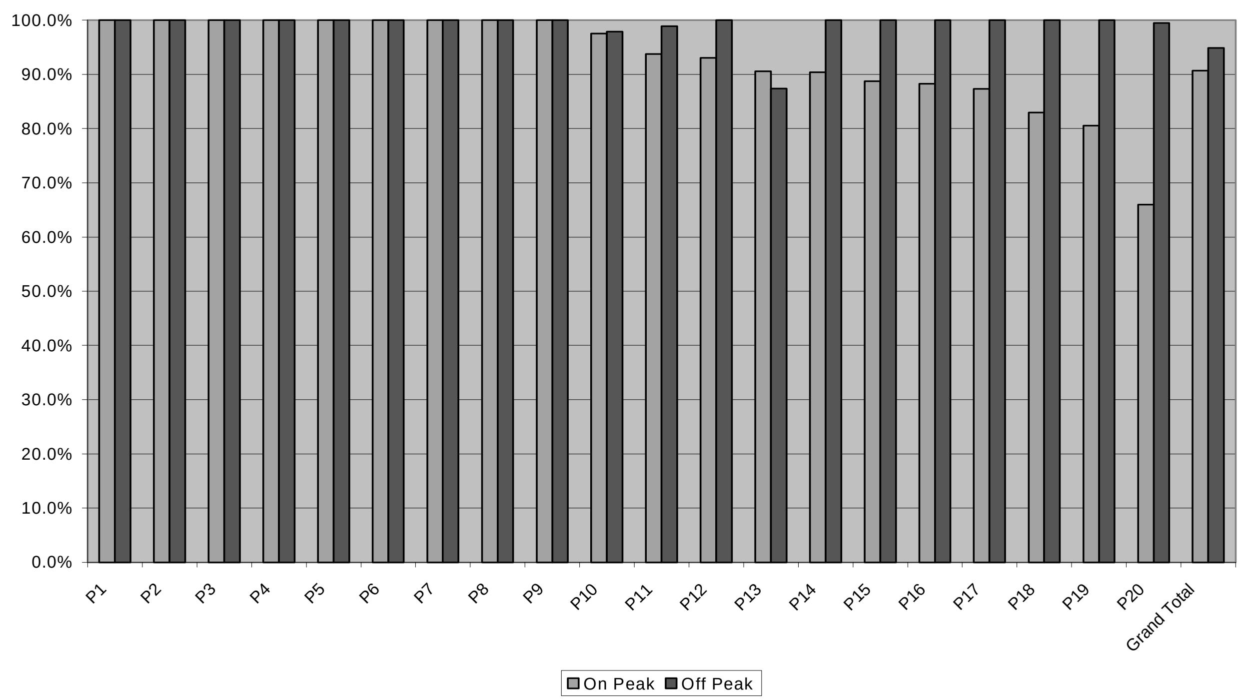

TABLE 8b

The graph shown in Table 8b reflects the results of the CRR market runs for the annual allocation to LSEs as well as the LSE monthly allocation for June. CRR bids for on peak had a combined total of 36,380 MW with 32,995 MW being cleared. The off peak numbers show a combined total of 27,956 MW in bids with 26,542 MW being cleared.

TABLE 9a

Market 2 and Market 8 Yearly and Monthly CRR Requests and Allocations to LSEs (in MWs)									
Class Type	(Market 2) Yearly - 2005		Percentage of Yearly Requested Allocation Received	(Market 8) Monthly - August		Percentage of Monthly Requested Allocation Received	(Market 2 and Market 8) Total Yearly and Monthly		Percentage of Total Requested Allocation Received
	Request	Allocation		Request	Allocation		Request	Allocation	
Off-Peak	15,857	14,952	94%	14,584	13,420	92%	30,441	28,372	93%
On-Peak	18,576	17,443	94%	22,035	19,987	91%	40,611	37,430	92%

Table 9a shows results for August, representing the largest number of CRR requests. An average of 92 percent of off-peak and 91 percent of on-peak CRRs cleared for the month. The total average off and on-peak yearly and monthly CRRs that cleared were 93 percent and 92 percent, respectively.

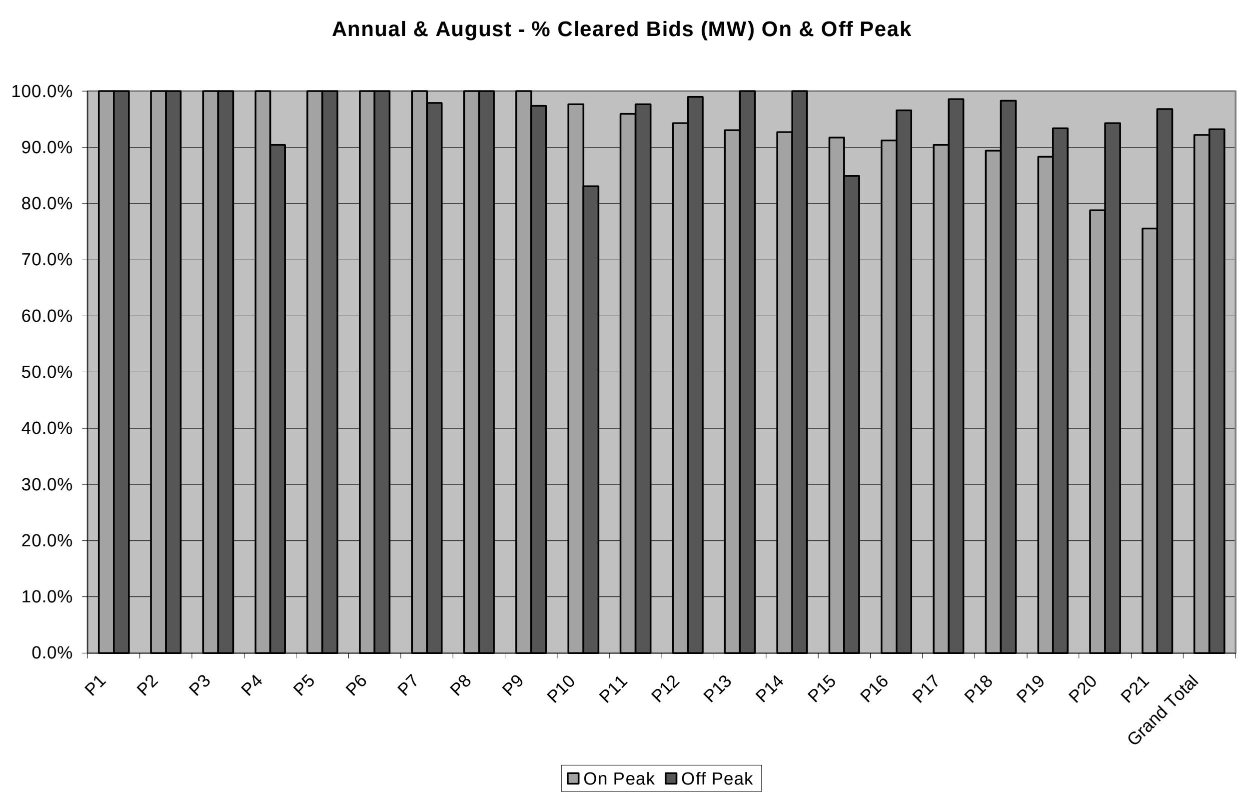

TABLE 9b

In Table 9b above the graph shows the results of the CRR market runs for the annual allocation to LSEs as well as the LSE monthly allocation for August. There were on peak CRR bids for a combined total of 40,611 MW with 37,429 MW being cleared. For off peak there was a combined total of 30,440 MW of bids with 28,371 MW being cleared.

TABLE 10a

Market 2 and Market 10
Yearly and Monthly CRR Requests and Allocations to LSEs
(in MWs)

Class Type	(Market 2) Yearly - 2005		Percentage of Yearly Requested Allocation Received	(Market 10) Monthly - November		Percentage of Monthly Requested Allocation Received	(Market 2 and Market 10) Total Yearly and Monthly		Percentage of Total Requested Allocation Received
	Request	Allocation		Request	Allocation		Request	Allocation	
Off-Peak	15,857	14,952	94%	9,893	9,412	95%	25,750	24,364	95%
On-Peak	18,576	17,443	94%	11,131	9,553	86%	29,706	26,996	91%

Table 10a results show 95 percent of November CRR requests cleared off-peak and 86 percent cleared on-peak. This resulted in total average clearing of 95 percent off-peak and 91 percent on-peak.

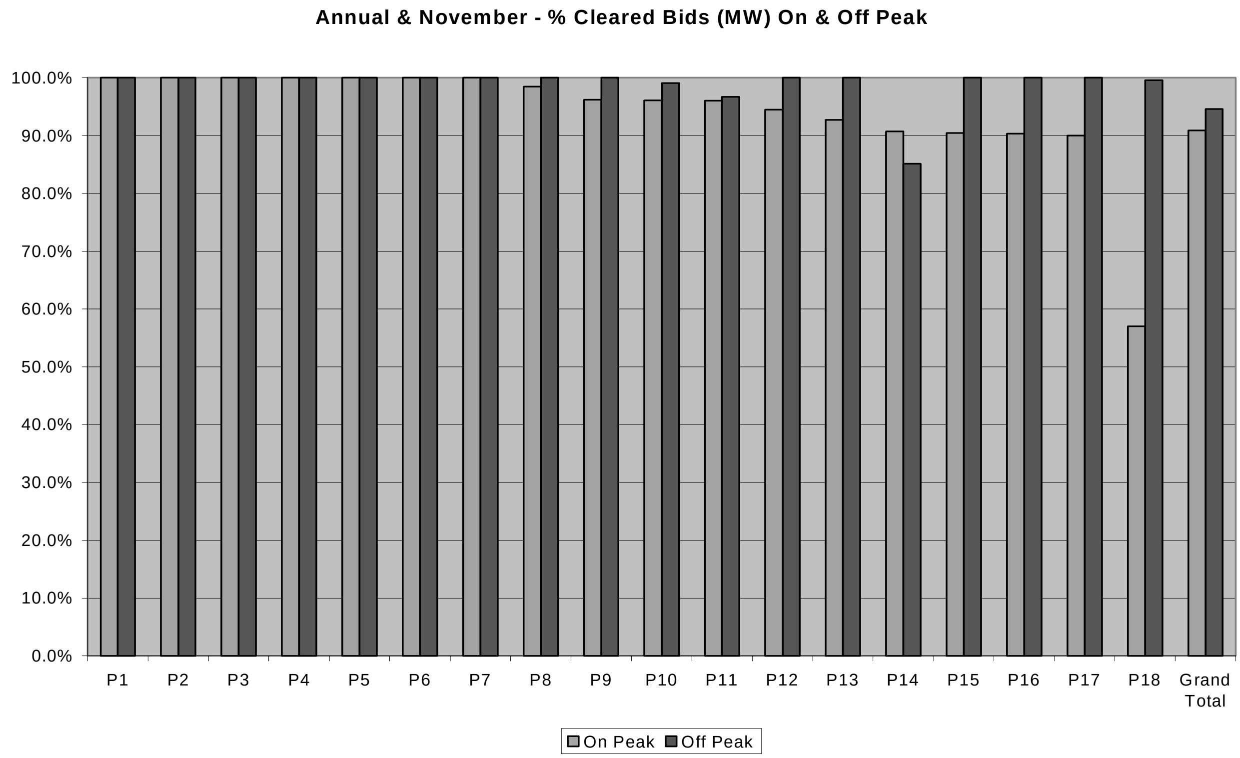

TABLE 10b

This last graph in Table 10b reflects the results of the CRR market runs for the annual allocation to LSEs as well as the LSE monthly allocation for November. CRR bids for on peak had a combined total of 29,706 MW with 26,995 MW being cleared. The off peak numbers show a combined total of 25,749 MW in bids with 24,364 MW being cleared.

7 Description of CRR Study Assumptions

As previously mentioned, a number of assumptions were made in the CRR Study. Some of these assumptions were optimistic (i.e., influenced results in a way that would suggest the release of more CRR allocations than will likely occur) while the majority of the assumptions were conservative. Following is a brief description of the optimistic and conservative assumptions; however this description does not attempt to determine or assess in detail the sensitivity of the assumption with respect to the amount of CRR that may be allocated.

7.1 Optimistic Assumptions

7.1.1 Scheduled Outages

For this first phase of the CRR Study we assumed that all transmission lines were in service, for both the annual as well as the monthly auctions. It is intended that this assumption hold true for the annual auction but that the monthly auction recognize projected outages. By recognizing projected monthly outages this will likely result in fewer CRRs being allocated. The exact parameters for determining inclusion or exclusion of a particular monthly line outage are yet to be determined.

7.1.2 Additional Operating Constraints

In order to expedite the study process, the same constraints that were used in LMP study 2, were used in the CRR study. This included all current Inter-zonal interfaces as well as 6 other constraints (i.e., the interfaces into the following areas: San Francisco, greater Bay Area, Humboldt, North Bay, San Diego and Fresno). In actual system operation, there are many other transmission constraints that are monitored and whose limits are adhered to. Many of these constraints, where applicable, will be modeled into the forward market LMP model. The CRR allocation process should be consistent with the forward market in terms of modeling to ensure revenue adequacy. In turn, the CRR simultaneous feasibility test should also be modeling these same constraints, where applicable.

In the actual production, it is envisioned that additional constraints will also be modeled and enforced. If more constraints are enforced, the amount to be allocated will be equal to or less than the amount allocated based on the current set of constraints.

7.2 Conservative Assumptions

7.2.1 Modeling of ETCs as Obligations

When determining how much capacity would be taken off the system due to Existing Transmission Contracts that have not been converted to the ISO we looked at contract capacity instead of historical usage data. In addition, a large number of the ETCs have bi-directional rights that are represented as a source and sink pair. For the CRR Study we modeled both directions despite the fact that a right with a source as a load point and the sink as a generator doesn't necessarily reflect actual scheduling practice. Both of these factors contributed to more transmission capacity being allocated for ETCs than what would normally be scheduled by the ETC holders.

The modeling of ETCs as options instead of obligations is another assumption that will limit the transmission capacity available for other users.

7.2.2 The Use of Network Service CRRs

In the original proposal, Network Service CRRs could be used to request CRRs. However due to software limitations, they could not be used for the study. When they are available to LSE in the actual production system, they could increase the amount of CRRs cleared since the SFT would determine a more optimal way to alleviate transmission constraints by using the bids submitted via the Network Service CRR.

7.2.3 Curtailment of Annual Term LSE CRRs

In the CRR allocation process, an upper bound amount is calculated for both the annual-term request and the monthly-term request. The LSE can request CRRs up to these upper bounds for the annual term and monthly, respectively. The calculation of the monthly upper bound will take into consideration the actual amount of the CRRs that the LSE was allocated during the annual-term allocation process. However, in the CRR study the calculation of the monthly-term upper bound was modified so that the annual upper bond was taking into consideration instead of what was actually allocated. The reason for this was the time constraint of the study. The CAISO asked that both the annual requests and monthly requests be submitted at the same time. If the requests for the month-term CRRs were delayed until after the annual-term allocation was completed this would have extended the study time.

If the LSEs were able to submit their monthly term CRR requests after the annual term allocation was completed, the amount of monthly term CRR requests may have increased and the pattern of source/sink CRRs may have also changed. The result could potentially be that more CRRs could have been allocated in the monthly term allocation process.

8 Conclusions and Discussion

The following conclusions can be drawn from the results of this study.

1. Based on modeling ETC rights as Options (consistent with the ISO's May and June 2002 MD02 filings) the quantity of non-converted ETCs that are simultaneously feasible is 95% for both off-peak and on-peak periods. On a day-to-day basis this is typically not a problem because ETC rights are not all used simultaneously. In the CRR allocation process, however, all ETC rights must be considered simultaneously because CRRs will be fixed for a month or a year. Thus, modeling all ETCs simultaneously may lead to a conservative release (under-release) of CRRs, whereas not modeling them simultaneously may lead to over-release and CRR revenue shortfall.

2. The percentage of total yearly and monthly CRR Options that could be allocated to previously converted ETCs, given the constraints of the network and the capacity reserved for non-converted ETCs, is 100% and 98%, respectively, for off-peak and on-peak periods.

3. The percentage of total yearly and monthly LSE requests that could be allocated, given the constraints of the network and the allocations of capacity to non-converted ETCs and CRR Options to converted ETCs, varied from 89% to 92% for on-peak CRRs and from 94% to 95% for off-peak CRRs.

4. A review of the constraint tables for each market run (Please see Appendix) indicates that the highest number of binding constraints occurs during the months of June and August (32 and 29, respectfully) and the lowest during the months of March and November (14 in both cases).

9 Recommendations

As with any study the results of this CRR Study are extremely dependent upon the assumptions made during the CRR Study time period. As has been noted previously in this document some of the assumptions were optimistic while others were conservative in nature but they were all based upon a market design that was first submitted in May and June of 2002. Due to the dynamic nature of the market design efforts that we are all going through it would seem logical that we can now look back at the process that was started almost a year ago and come up another set of working assumptions to provide us with another set of data based on taking the CRR process in a slightly different direction. If the results of this initial CRR Study have provided us with answers to some questions it has also provided us with new questions that we would like to have addressed. At this point we need to decide if it would be worth everyone’s time and effort to modify the base set of assumptions and start a second phase CRR Study or be satisfied with the results of the CRR Study as provided.

10 Commentaries by Shmuel Oren and Robert Wilson

CAISO asked Dr. Shmuel Oren of the University of California and Dr. Robert Wilson of Stanford University to review this study and provide their observations. Their comments are shown below.

10.1 Comments by Shmuel Oren

10.1.1 Objective and Approach of the CRR Study

It is my understanding that the ultimate objective of the CAISO CRR Study is to demonstrate that an LMP-based market design has the potential to improve market and system efficiency and to benefit consumers without making any market participant worse off compared to the status quo. The critical issue of contention in an LMP-based design is the fact that wholesale prices in the day ahead market will vary among locations to reflect congestion and scheduled bilateral transactions in the day-ahead market will be exposed to congestion charges that are based on the locational price difference between the points of injection and withdrawal. Market participants can be immunized against such exposure by obtaining point-to-point Congestion Revenue Rights whose payoffs exactly offset the congestion charges between the respective points of injection and withdrawal (for bilateral transactions) or the nodal price differentials for those who sell and buy their power in the day-ahead CAISO markets.

Such CRRs provide perfect hedges against exposure to locational price differences inherent in an LMP-based market design. Thus if all market participants can obtain CRRs that reflect their usage patterns and entitlements to the use of the transmission system then they will be revenue neutral with respect to the implementation of an LMP-based market if they continue to use the system as before. However, the financial nature of the CRRs provides opportunities for win-win efficiency-improving transactions that will make everyone better off and thus increase consumer benefits. Unlike the old system where entitlements to the transmission system had a “use it or lose it” characteristic, conversion of such entitlements to financial CRRs enables the holders to capture the full value of the entitlement even if they do not use the system because they were able to replace a designated expensive resource with a cheaper resource that was available. Such efficiency transactions will ultimately reduce the cost of electricity to California consumers without making anyone worse off. The key question is whether it is possible to allocate a sufficient number of CRRs to cover all entitlements and legitimate claims by market participants to the transmission system without running a deficit that would require the CAISO to impose additional uplift charges that might reduce consumer benefits. The simultaneous feasibility test imposed on the CRR allocation guarantees that payments to CRR holders can be covered by revenues from congestion charges imposed on scheduled bilateral transactions and revenues resulting from differences between buy and sell prices (merchandising surplus) in the CAISO day-ahead market.

The above discussion validates the immediate objective of the CAISO CRR study to demonstrate the feasibility of issuing enough CRRs to cover all entitlements and legitimate claims by market participant within the limitations of the simultaneous feasibility test. Specifically it establishes the linkage between this immediate objective and the ultimate goal of demonstrating the benefits of an LMP-based design to California consumers. In meeting the objectives of the CRR study the CAISO has adopted a sound methodological approach that is deliberately designed to err on the conservative side. In other words, the estimates of CRR coverage resulting from the study are likely be lower than what the system will be able to support without subsidy. Following is a detailed discussion of some aspects of the methodology used in the study and their implications along with some suggestions for improvements.

10.1.2 Discussion of CRR Study Details

Network Modeling:
The study employs a full network model, which is consistent with the proposed market design and the LMP study. The model captures most of the current system constraints but enhances the system capacity to reflect upgrades that will be completed by 2005. The line rating used conforms to reduced rating reflecting contingencies and voltage limits. These limits and the various modeling assumptions used to approximate the external portion of the network are methodologically sound and consistent with the version of the network model that will determine congestion charges and CRR settlements in the year 2005 time frame.

Accounting for ETCs:
ETCs are modeled as CRR options that entitle their holder to the associated congestion rents between specific sources and sinks but does not obligate them to execute the transaction or make payments when congestion between these points is reversed. This modeling approach is consistent with the contractual rights of ETCs. The study makes a further conservative assumption by ignoring the benefits from any counterflow that may be created when an ETC is exercised. With this restriction ETCs can be accounted for by simply deducting from the line ratings the capacity taken by flows that ETCs produce (but not adding counterflows to the capacity). When ETCs exist in opposite directions, the study takes a worse case scenario assuming that they are not exercised simultaneously and hence deducts from the available capacities in both directions the full impact of each ETC. When ETCs have network rights that entitle them to choose points of injection or withdrawal, the study again makes a conservative assumption by deducting the full capacity on all possible source-sink pairs as if the ETC were exercised simultaneously between all possible pairs (which is clearly not possible). The only area where the study is making some allowances concerns ETCs that clearly overload certain lines like path 15. In such cases the ETCs are scaled to conform with the line capacity. Such scaling is justifiable since in reality ETCs have taken advantage of the non-synchronous use of the transmission system and sometimes of known counterflows. Such asynchronous historical use will need to be considered when ETCs are converted to financial rights and a scaling strategy is a reasonable solution to the problem. While the scaling may leave an ETC holder under hedged against congestion

during its peak use of the transmission system, such shortfall will be covered by excess payoff from the converted rights during its off peak (when the lines are used by others).

<u>CRR requests by LSEs</u>
LSE requests were modeled as CRR obligations that allow the accounting of counterflows to enhance system capacity. This is a reasonable assumption that is consistent with practices in the Eastern ISOs and with historical use of the transmission system in California. Specifically, counterflows have traditionally been relied upon in generation dispatch and to the extent that LSEs are awarded CRRs based on historical use it is reasonable that the associated counterflows will become an obligation. According to the report, the allocated CRRs are based on peak use excluding the 0.5% top peak period. The financial implication of such exclusion is not clear but it is reasonable to assume that there is sufficient asynchronicity in the use of the system so that the top 0.5% peak use between different source and sink points will not coincide and hence the peaks will be accommodated by the system. The extent to which the LSE is exposed to congestion charges during this 0.5% peak usage that is offset by CRR payoff surplus in the remaining 99.5% of the time is not clear and may deserve further study.

The LSE data was obtained with respect to aggregate load points but was broken down for the purpose of running the SFT software according to some weighting scheme. It is not clear how such disaggregating of the load affects the results. I would recommend that some sensitivity analysis be performed to test the robustness of the results with respect to the weights used in fragmenting the load.

<u>Software credibility:</u>
The Alstom SFT software used to test feasibility of the CRR allocation is known in the industry and it has been used in market operations by various ISOs such as PJM and ERCOT. I do not see any reason to doubt that it produced correct results for the network model and input data it was fed.

<u>Market cases:</u>
The 10 market runs performed represent a good sample of market conditions corresponding to various months under peak and off-peak load assumptions. The first case tests the feasibility of accommodating all non-converted ETCs on an annual basis while the second case tests feasibility of accommodating annual CRRs allocated to converted ETCs and LSE claims with 75% of the network capacity. The other market runs examine the feasibility of accommodating annual and monthly allocations for various months on and off peak. The runs properly account for the priority given to the ETCs over LSEs' claims when allocations need to be prorated to achieve simultaneous feasibility. The results are very positive considering all the conservative assumptions showing that under most cases 90% of the claims can be accommodated. Only in March during the peak must the allocation be reduced to 80% of the claims to reach feasibility. Given the conservative nature of the underlying assumption, which will be discussed, further below, the percentages produced by the various tests should be

regarded as rough lower bounds. A further study with more realistic (less conservative) assumptions is likely to show that a higher percentage of claims can be accommodated.

10.1.3 Prospective vs. Retrospective Analysis.

The study is based on a prospective analysis for the year 2005. The rationale for this decision is that the new market design will not take effect until then and by 2005 several new transmission expansion projects will be completed while some ETCs will expire. This approach has advantages and disadvantages.

Advantages:

- It enables the consideration of future transmission resources that will accommodate more rights. Since no new rights are being offered while some ETCs will reach expiration, the consideration of new resources, e.g. on Path 15, paints a more rosy (and realistic) picture then a prospective analysis based on historical data would have.

Disadvantages:

- The study must rely on data provided by LSEs and PTOs, which have a clear incentive to inflate their requirements.
- This study is not exactly compatible with the LMP study that would have enabled the use of prices to assess the financial consequences of the CRR allocation to individual market participants and to the ISO.
- Because the study is based on projections and estimates it might lack credibility and be subject to disputes.

Alternative:

- Conduct a retrospective study, at least as a check point, based on actual assets and utilization that can determine what would have been the financial implication of the proposed allocation methodology (on the Market Participants and the CAISO) had the CRRs and an LMP system been in place during 2002. Such an approach, which is consistent with the LMP study, may provide an undisputable benchmark from which one can extrapolate to the future.

10.1.4 Conservative nature of the study

While accounting for prospective resources to accommodate claims based on past usage of the network will enable accommodation of more CRRs, the study as a whole is very conservative in its approach and to the extent that the projected resources will in fact be in place, the results of the study should be viewed as producing a lower bound on the CRR coverage. In the following I will elaborate on the various conservative assumptions and methodological aspects of the study.

- The study does not account for improvements to the transmission system that will occur past the year 2005. Such further improvements will increase the possible CRR coverage.

- The LSEs have incentives to inflate their claims; hence the percentage coverage produced by the study is likely to understate the possible coverage under a rigorous verification of claims
- Historical usage relied on counterflow provided through out-of-merit dispatch. Hence some of the capacity underlying ETCs and claims by LSEs might have been "virtual" in nature. Converting all such claims to CRR options may result in insufficient capacity to accommodate all the claims. When actual allocations will be determined, chances are that some of these claims will be converted to CRR obligations thus enabling more coverage, as will be discussed below.
- In the case that the Simultaneous Feasibility Test (SFT) produces an infeasible result, the proposed approach is to prorate the awarded CRRs proportionally until a feasible allocation is achieved. This approach may result in underutilization of the available resources whether the utilization is measured in terms of Dollar value (i.e., the value of hedged congestion charges) or in terms of MWs awarded (see discussion below). Furthermore, proportionally curtailing all point-to-point CRRs that impact an overloaded element or corridor will result in curtailment of CRRs that have little impact on the overloaded facilities in absolute MWs and consequently reduce utilization by such CRRs of uncongested facilities.
- The SFT test applied to CRRs implicitly assumes that all CRRs are exercised simultaneously and does not account for the asynchronous nature of actual transmission usage. The test attempts to ensure that the CRR payoffs will not exceed congestion revenues at any point in time rather than on average. Applying the test in this fashion will result in overly conservative CRR awards and congestion revenue surplus for the ISO. Under such a conservative allocation the CAISO will likely end up with a revenue surplus.
- Any SFT-based allocation is based on a hypothetical operating point treating all CRRs as simultaneous bilateral transactions. Such an allocation is intrinsically conservative since it does not allocate rights to flowgate capacities that are not utilized at the "CRR operating point" but may be utilized in real time as the real operating point shifts around according to economic dispatch criteria.
- The current study assumes that CRR options, which represent converted ETCs, do not produce counterflows in the simultaneous feasibility test. This assumption overstates the payoff of such CRRs and subsequently over restricts the number of CRRs that can be allocated. In reality a CRR option entitles the holder to the nodal price differential between two locations whenever that differential is positive. The nodal price difference, however, is the sum of shadow prices on all the links carrying the flows multiplied by the respective power distribution factors. That sum can be positive even if some of the components are negative. Negative components correspond to counterflows produced by a transaction, which on the whole is profitable. By ignoring such counterflows the study overestimates the payoff to CRR options since such payoff, although positive, will be reduced by the components corresponding to counterflows. In mathematical terms: if we denote by P_i and P_j the nodal prices corresponding to two nodes then the payoff to a 1MW CRR option between the two nodes is $\mathrm{Max}[0, P_j - P_i]$. If we denote the shadow prices on a link k by S_k and the shift factor corresponding to a node i to node j transaction with respect to line k as f_k then $P_j - P_i = \sum_k (S_k \times f_k)$.

Ignoring counterflows amounts to assuming a payment to CRR options of $\Sigma_k Max[0,(S_k X f_k)]$. However, $Max[0, P_j - P_i] = Max[0, \Sigma_k(S_k X f_k)] \leq S_k Max[0,(S_k X f_k)]$. So ignoring counterflows corresponding to CRR options overcompensates such options and results in under-allocation of CRRs. While in terms of real power flows the CAISO may not count on counterflow produced by ETC holders when these ETC are converted to CRR options, such options will always be exercised when they have a positive payoff so the financial equivalent of their corresponding counterflow, which takes the form of a reduced payoff, can always be counted on.

Possible modifications in future studies that will permit a more aggressive CRR allocation include:

- Increase the CRR allocation and apply an "average SFT" to evaluate ISO congestion shortfall on a monthly or annual basis as measured in MW or in Dollars (measuring CRR allocation adequacy in MW is equivalent to assuming that all CRRs and point to point congestion are settled at a fixed value of $1/MWh). Implementing a more relaxed annual revenue adequacy criterion would allow the CAISO to use congestion revenue surplus during some periods as well as CRR auction revenues to cover shortfall between congestion revenues and CRR payoffs in other periods. The implementation of such a relaxed revenue adequacy test would require, however, a full simulation of daily congestion and CRR settlements, which would be much, more computationally demanding than the sampling approach used in the current study.
- If allocated CRRs do not meet SFT then curtail only CRRs whose impact on overloaded elements exceed X% (e.g. X=5) similarly to NERC's TLR. Such a scheme will eliminate reductions in CRRs awards on unimpacted point-to-point pairs due to their small impact on congested lines and will result in an overall increase in CRR allocations.
- If allocated CRRs do not meet SFT then optimize CRR allocation using either a Dollar value criterion or total MW criterion subject to SFT.
- Modify SFT to account for counterflows corresponding to positive-valued CRR options.

Figure 2 below provides a simple illustration of a nomogram for a three-node system shown in Figure 1 that will clarify some of the points discussed above. The nomogram describes the feasible allocations for point-to-point CRR obligations and CRR options. The outside boundary of the nomogram represents all possible feasible combinations of CRR obligations between the two-generation nodes 1 and 2 to the load at node 3, accounting for possible counterflow. The inner "chopped" nomogram represents all possible combinations of CRR options, which exclude CRRs that rely on counterflows. Noticeably, the issuance of CRR options reduces the possible number of CRRs. According to the conservative nature of the curtailment procedure used in the study, the figure starts with an infeasible allocation at point outside the nomogram and shows the result of proportional curtailment vs. optimized feasible allocation. Note that when the allocation criterion is to maximize total MW awards the objective function (represented by a dashed sloped line touching the feasible region at point Y) has a 45-degree slope. Using a dollar value based on LMPs would produce a different slope and therefore a different optimal allocation.

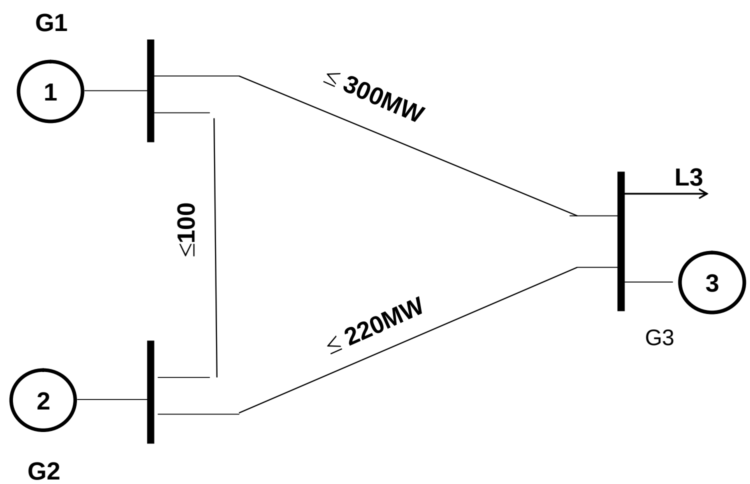

Figure 1: Three Bus Example

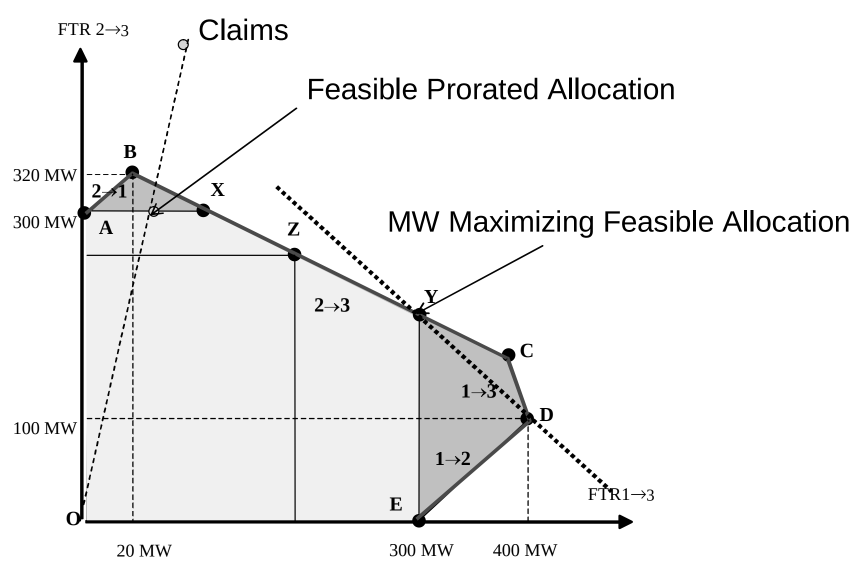

Figure 2: Nomogram for three bus example

10.1.5 Summary

In sum, the CAISO CRR study is methodologically sound and is heavily biased on the conservative side. The results show that even under the stringent assumptions the system can accommodate in most cases over 90% of the claims. Only in one case (Market 4 On-Peak) it was necessary to prorate the claims to 80%. Given the conservative assumptions these are very promising results suggesting that indeed CRR allocation can produce a Pareto Superior (win-win) outcome under the LMP based market design proposed in MD02. However, it may be useful to conduct a follow-up study that will incorporate some of the suggestions outlined above that will verify that a broader CRR coverage is indeed feasible.

10.2 Comments by Robert Wilson

I was asked by the CAISO to review the "Congestion Revenue Rights Study Report", and to provide comments on the general methodology and conclusions of the study. My comments below are written after seeing a draft of Dr. Shmuel Oren's comments. I agree with his comments but also state my own. Because I have not examined the software, the full network model, the specific transmission constraints, nor data from load-serving entities [LSEs], my comments address only the general economic aspects of the study.

Summary of my conclusions. In my view the study's methodology is a valid means of estimating a lower bound on the percentage of predicted transfers that can be accommodated by the grid capacity anticipated in 2005 without resorting to redispatch of generation to alleviate congestion. This estimate therefore indicates a percentage of LSEs' requests for congestion revenue rights [CRRs] that can be accommodated without significant risk that CAISO's revenues from congestion charges would be insufficient to cover payments to the CRRs issued. That is, because the lower bound satisfies a stringent test of joint feasibility, it ensures revenue adequacy for CAISO. This percentage of predicted transfers therefore translates into a lower bound on the percentage of day-ahead congestion revenues that, subject to CAISO's revenue adequacy requirement, can be allocated to LSEs via CRRs to hedge their financial exposures to congestion charges. The methodology used in the study is remarkably conservative; hence I have no doubt that the percentages calculated in the study are valid lower bounds if the base case used for the full network model is appropriate and all constraints were included.

My subsequent comments are divided among general considerations, sources of optimism, and sources of conservatism, accompanied by possible alternatives. Because the study makes conservative assumptions, I include (as requested) prospects for improving the extent of the LSEs' hedges against congestion charges.

10.2.1 General Considerations

Advantages of the study are that (a) it uses a full network model with an external representation, comparable to the intended implementation of MD02 with nodal prices, (b) all thermal and interface security constraints that would be enforced in practice are apparently included in the linear-programming formulation, and (c) ALSTOM ESCA's software has an established record at PJM and this firm will provide CAISO's software too. The study does not include voltage and stability constraints, nor account for losses, but otherwise the study apparently provides a representation of feasible flows that is reasonably accurate from an engineering viewpoint. I cannot judge the choice of the operating point for the base case.

Restricting each LSE's requests for CRRs to an upper bound that is the 0.5% point (4 hours/month) on its submitted load duration curve is a reasonable starting point for the study, but it means that percentages of accepted CRR requests must be interpreted relative to this imposed bound on the requests allowed. I presume that

LSEs adapted their requests to the study's restriction to point-to-point rights even though the eventual implementation will include network service rights.

The necessary scaling of ETCs on Path 15 may be indicative of a wider pattern of existing firm rights as perceived by LSEs that actually depend on non-synchronous loads and/or redispatch of generation. Treating unconverted ETCs as options is necessary given their contract rights. Providing LSEs with CRRs that are obligations is useful in this study so that the software can recognize counterflows, even if the final implementation might use options. Similarly, the use of load distribution factors and load sink reduction gives a better representation of local flows.

The study focuses on MWs of flows over the grid, but LSEs are concerned about financial exposure. As a rough check on the study results I suggest calculating possible CRR coverage as 100% minus the percent of counterflows purchased by CAISO (say, on a hot summer afternoon) by redispatching generation to alleviate congestion. Similarly, I would obtain a rough estimate of financial exposure from the historical cost of redispatch. I also endorse Dr. Oren's proposal for a retrospective study.

10.2.2 Sources of Optimism

The study treats each of the four typical hours (in March, June, August, November) as certain events, with no allowance for unfavorable contingencies that might expose LSEs to high congestion charges – such as the four hours per month excluded from their allowed upper bounds on requests. Similarly, each LSE's forecast is interpreted as the median of the likely range, whereas a heat wave might imply that most LSEs would be above these medians simultaneously; i.e., deviations from their predicted loads are highly correlated. In order to better calibrate their risk exposure, LSEs might like the study to be augmented by repeating the simulation of the August hour with higher forecasts. No capacity is reserved for ancillary services. I cannot judge the impact of ignoring the 230 MW of load comprising bids less than 0.5 MW; the bids seem small but the total is significant.

10.2.3 Sources of Conservatism

There are several reasons to interpret the study as conservative in its estimate of the CRRs that can be allocated to LSEs. ETCs were treated as though they will always be fully used (although those on Path 15 were scaled down). The load data and forecasts were provided by the LSEs themselves, so they were hardly likely to minimize peak loads or to understate their requests for CRRs. All requests were treated as perfectly synchronous loads. All power transfer distribution factors were used even though other ISOs zero-out those that are very small; as Dr. Oren mentions, this means that large loads far away from congested branches are curtailed by the same proportion as all others. Of the 4699 branches and transformers, at most 33 were congested, yet the percentage coverage gives no credit for additional rights on uncongested branches that might be allocated to LSEs and that would be valuable in contingencies. The monthly allocations treated the annual allocations as fixed, whereas PJM allows reconfiguration of annual CRRs in its monthly auctions (I cannot judge whether the 75-25% split between annual and monthly capacity biased the results).

The most fundamental source of conservatism is the complete exclusion of redispatch that would enable more CRRs; similarly, no allowance was made for regulating imports in ways that might alleviate congestion. All non-ETC bids were treated as being offered at the same price (other than priority given to annual requests from previously converted ETCs), with the net result that all such bids were curtailed proportionally to achieve feasibility. Dr. Oren's Figure 2 illustrates that exclusion of redispatch and use of CRR options that prevent reliance on counterflows makes the joint feasibility test more stringent by shrinking the feasible set of transfers. Further, proportional curtailment need not maximize the mega-Watts of CRRs that can be issued to LSEs, nor the financial value of the hedges provided to LSEs.

10.2.4 Regulatory Considerations

The purpose of the study is to estimate the amount of CRRs that can be issued to LSEs within the limits imposed by a stringent test of joint feasibility in which the CRRs are modeled as power flows. In turn, this test is used to ensure revenue adequacy in every hour of the year. That is, by imposing the joint feasibility constraints, the CAISO expects to incur no deficit in any hour because revenues from congestion charges will be no less than payments to CRRs – even though in some contingencies the CAISO will run a net surplus. However, recent changes in FERC policy may alter the application of the joint feasibility test. FERC's White Paper issued in April states:

> "If an RTO or ISO uses locational pricing, it must ensure that each existing firm customer (including transmission owners with a service obligation for native load) has the opportunity to obtain FTRs [*=CRRs*] equivalent to that customer's existing firm rights. We will ensure not only that existing customers retain their existing rights, but also that they have the ability to obtain rights for future load growth. Customers who paid for transmission for load growth can retain the FTRs for that capacity. The FTRs that are offered by the RTO or ISO must, in the aggregate, be consistent with the physical limitations of the transmission system.[8]
>
> > [8]Existing rights to service will be preserved. If necessary to meet these requirements, the RTO or ISO will create counterflow FTRs to make the aggregate set of FTRs physically feasible. If this results in a revenue shortfall, it could be recovered through an uplift charge."
>
> (FERC, "Wholesale Power Market Platform", Appendix A, text and footnote 8, April 28, 2003)

This new policy seems to indicate that FERC would allow CAISO to allocate sufficient CRRs to hedge LSEs against congestion charges for the full amounts of their existing firm rights, and in some cases future load growth.

From this perspective it may be useful to interpret the study results in terms of the magnitude of the counterflow-CRRs required to hedge all existing firm rights and still satisfy the test of joint feasibility. Alternatively, instead of counterflow-CRRs the CAISO could consider the cost of contracting annually or monthly for redispatch services sufficient to eliminate congestion associated with CRRs violating joint feasibility. Similarly, Dr. Oren proposes a relaxed revenue adequacy criterion based on the annual average of CAISO's hourly surpluses and deficits from revenues from congestion charges and payments to CRRs. In any case, a follow-on study might estimate CAISO's annual financial deficit and the resulting increase in the grid management charge if more CRRs were assigned to LSEs.

10.2.5 Concluding Comments

Even though the study's results are encouraging, the predominantly conservative methodology suggests the matter might be studied further. A subsequent study could focus on the prospect that a less conservative formulation, or equivalently a relaxed criterion for revenue adequacy, could justify CRR allocations above the 90% or so indicated in the present study. Also useful would be an estimate of the financial consequences of larger CRR allocations. An LSE might benefit most from an analysis of its unhedged financial exposure to congestion charges, not just the amount of CRRs it is eligible to receive.