California ISO

Shaping a Renewed Future

California ISO

2012 Grid Management Charge Draft Final Proposal

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Executive Summary

ISO management intends to take this draft final proposal to its Board of Governors for approval at its March 2011 meeting, and as such is the last step in the design process for the 2012 Grid Management Charge. Following discussions with stakeholders since the last posted proposal document on January 13, and further analysis by ISO staff, this draft final proposal incorporates some final modifications that are listed at the end of this section.

This paper is the culmination of the following previously published papers and data sets:

- The cost of service discussion paper published October 8, 2010
- The straw proposal published on November 11, 2010
- The comparison data published December 2, 2010
- The modifications to the straw proposal published on January 13, 2011
- The revised comparison data published on January 13, 2011
- The revised comparison data published on February 9, 2011

Building upon the cost of service study functionalization and cost allocation steps reported in the October 8, 2010 Cost of Service discussion paper, this draft final proposal reviews the guiding principles and the framework for the new GMC cost categories. The draft final proposal goes on to describe the ISO's classification (determination of billing determinants based on customer cost causation factors) of those costs, the rate design produced by applying the billing determinants and some hypothetical, aggregated bill impacts. The October 8 discussion paper detailed the process the ISO followed to utilize its activity based costing system to allocate the costs of its activities into three main GMC cost categories or buckets (Market Services, System Operations, and CRR Services), and four transaction fees (bid segment fee, inter SC trade fee, CRR bid fee, and SCID fee). This approach offers significant improvements to the current GMC structure by increasing the amount of direct allocations of costs to buckets, reducing forecasting errors through rate simplification, reducing the number of charge codes, and simplifying the calculations of these charge codes.

This document describes the ISO's draft final proposal for classifying costs to users of the ISO's services. The ISO proposes that the three GMC charge categories be allocated based on gross MWh (capacity and CRR holdings) and MWh (energy). The Market Services category includes awards of ancillary services, and schedules and dispatch instructions of generation, imports, load, and exports. The System Operations category includes all flow quantities for generation, load, imports, and exports. The CRR Services category includes the total MWh quantity awarded through both the allocation process and auction.

The ISO's draft final proposal to allocate the charges as follows to each user of the ISO's services: The Market Services charge will be applied to the scheduling coordinator's gross absolute value of awarded MWh of energy and MW of AS in the forward and real time markets. The System Operations charge will be applied to the scheduling coordinators gross absolute value of actual MWh of real time energy flows. The CRR Services charge will be applied to each scheduling coordinators total MW holdings of CRR that are applicable to each hour. The three administrative charges will be applied to each scheduling coordinator based on their use of the associated transactions.

This draft final proposal also incorporates the modifications that were published in the January 13, 2011 paper as well as others discussed on the February 8, 2011 conference call. The modifications are summarized below and will be addressed in more detail later in this draft final proposal.

- To introduce a grandfathering provision to mitigate the impact of the 2102 GMC design on certain supply contracts by excluding the energy supplied from those generating units from the System Operations charge;
- To eliminate the three-year phase-in for the application of the System Operations charge to supply energy flows;
- Provide for treatment of Transmission Ownership Rights (TORs);
- Provide for application of Scheduling Coordinator Identification (SCID) fee;
- Eliminate Station Power Fees from GMC;

- Exclude MSS Load Following Energy from Market Operations charge.

This paper also addresses issues from the December stakeholder meeting for which the ISO is not proposing changes to the GMC design proposal. Last, we will discuss the proposal for a three year revenue requirement cap.

Guiding Policy and Ratemaking Principles

The ISO is using the following guiding policy principles to conduct its cost of service study and develop the framework for a new GMC structure:

1) **Cost Causation** – Costs will be properly allocated to the correct GMC cost categories and charged to those who benefit from or utilize those services.
2) **Focus on use of ISO services, not market behavior** – The new GMC design will reflect its primary purpose as a vehicle for recovering the ISO's revenue requirements based on each participant's use of the ISO's services, not as a tool for shaping incentives based on market or operating behavior. Incentives such as these are appropriately addressed through the design of the market structure and market rules. In addition, SCE's comments on the October 8, 2010 discussion paper highlighted a similar theme, "there should always be a final check on GMC rates, and a continuous monitoring, to ensure that GMC rates are not unduly negatively affecting market outcomes." The ISO agrees that a properly designed GMC should seek to do no harm (negatively affecting market outcomes), avoid imposing negative incentives (address negative market behavior such as deviations), and should be simply a mechanism to recover ISO revenue requirements in a manner which minimizes market impacts.
3) **Transparency** – Costs and billing determinants will be clear, visible, and understandable to all market participants.

4) **Predictability** – Market participants will be able to determine in advance what their GMC costs will be depending on their activity.

5) **Forecastability** – The rates will utilize billing determinants that can be easily forecasted by both the ISO and market participants. This should result in fewer rate adjustments during the year.

6) **Flexibility** – The new GMC structure will easily accommodate future market enhancements without excessive complexity or disruption to the overall structure.

7) **Simplicity** – The new design will simplify the current GMC structure by reducing the amount of varying bill determinants and the number of charge codes.

The steps included in conducting a cost of service study are:

1) Functionalization -	The process by which various activities are defined and sorted into service categories (functions and sub-functions) to reflect the different services provided by the ISO.
2) Cost Allocation -	The process by which the costs of providing services are allocated to the service categories (functions and sub-functions).
3) Classification -	The determination of billing determinants based on the customer cost causation factors.
4) Rate Design -	The process for deriving rates that divides the revenue requirement for each service category by the billing determinants.
5) Bill Impacts Analysis -	An evaluation of the impacts that the rate design will have on individual customer bills.

The ISO has completed the functionalization and cost allocation steps in accordance with these fundamental ratemaking principles and described the results (summarized in the section below) in the October 8, 2010 discussion paper. In this draft final proposal the ISO: 1) proposes a classification methodology (customer billing determinants) that can be used to allocate the costs in each service category; 2) provides some rate design examples using hypothetical rates and historical data; and 3) presents aggregated bill impact information.

The 3 GMC Cost Categories

As described in the October 8, 2010 discussion paper, an examination of the ISO's new nodal market systems process map of customer activity revealed the following:

Customers submit bids	**>>**	**Market systems award / schedules**	**>>**	**Energy flows**

In addition, there are processes related to Congestion Revenue Rights (CRRs).

Based on this process map, the following three cost categories were developed:

1. Market Services
2. System Operations
3. CRR Services

This structure is very similar to what other ISOs and RTOs with nodal markets have implemented to recover their administrative charges.

Using these three categories, the ISO's level 2 activities were mapped as either: 1) all in one category or not in the category (100% or 0%), 2) a split between two categories (50% / 50%), or 3) partially in one category or another (80% or 20%), or in the case of CRRs, a small portion of the activity (10%). This mapping was also applied to the software underlying the debt service portion of the revenue requirement. Indirect costs are allocated proportional to direct costs.

Grandfathering Provision

The ISO believes that the GMC draft final proposal is equitable and adheres to the stated guiding principles, but does acknowledge that the new design results in significant bill impacts to certain customers. A primary factor behind the large impacts is that the current GMC does not charge for through-put (i.e., energy flow in MWh), but does assess charges based on behavior, particularly real-time uninstructed imbalance energy or deviations. In contrast, under the proposed 2012 GMC structure the billing determinant for System Operations will be total energy flow MWh, without regard to whether the flows were forward scheduled, instructed or uninstructed. Under today's GMC, a supplier that puts through the same volume as a load serving entity consumes pays approximately 60% less. For example, under the existing GMC, a base load generator pays $0.06 per MWh while an equivalent level of load pays $0.65 per MWh.

Stakeholders offered comments suggesting that the ISO should consider either grandfathering certain generation units or phasing in the charges to supply over a period of time.

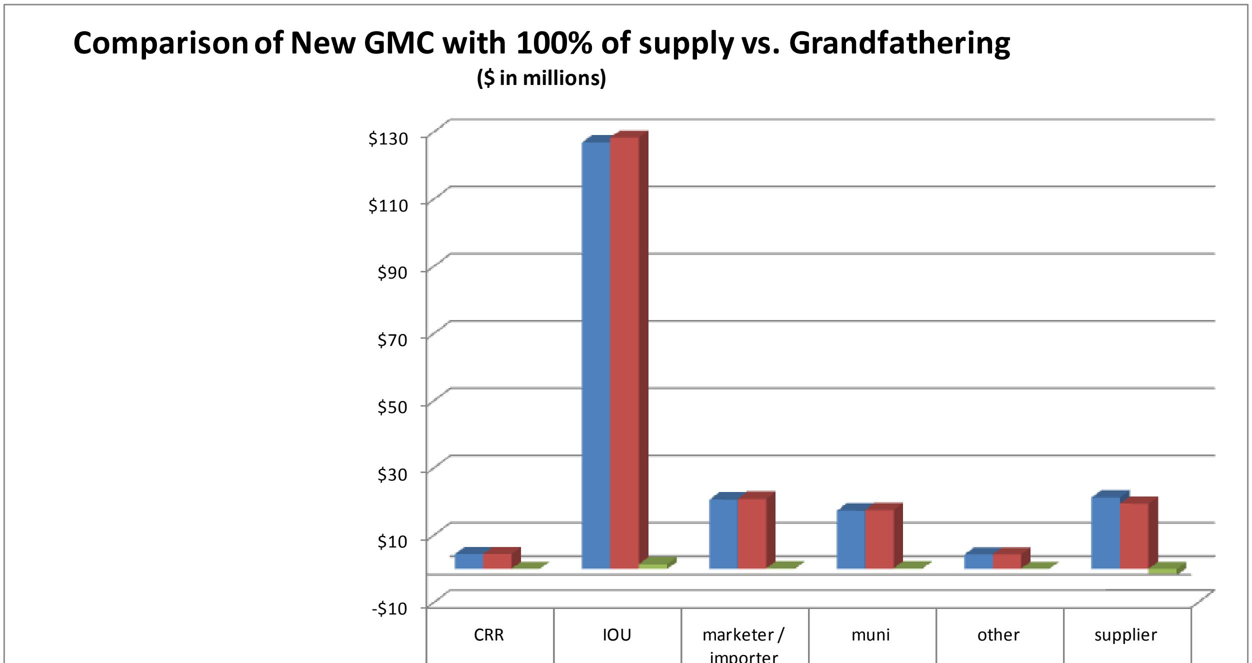
The ISO previously proposed a three-year phase-in approach, as discussed in the January 13 paper. After discussing this approach with stakeholders and performing further analysis to examine its effectiveness in addressing the identified issue, the ISO has concluded that a grandfathering approach would be the preferred option to mitigate rate impacts on a finite number of customers. To be clear, the ISO proposes to implement the grandfathering provision instead of the phase in approach – not a combination of the two. The ISO's analysis indicates that grandfathering certain baseload generator units that have contractual restrictions preventing the recovery of additional GMC charges by the supplier is a sufficient mitigation technique that specifically targets the impacted units and mitigates the GMC cost impacts for those units while causing minimal impacts on other participants, in contrast to the phase-in approach. Moreover, this method will limit the cost impact of the mitigation to other market participants by reducing the number of MWh that are excluded compared to the phase-in approach.

The proposed grandfathering provision would exempt units that meet the criteria from the System Operations charge until the first opportunity to renegotiate the contract or until the contract expires. An officer of the generation owner company will be required to provide the ISO a signed affidavit attesting to the information that demonstrates the contract's eligibility for grandfathering.

The criteria that will be used for determining units that are eligible for the grandfathering provision are:

- The contract precludes the supplier from recovering the additional GMC costs under the 2012 design from the buyer;
- The contract must have been executed prior to 1/1/2011;
- The duration of the contract must be three years or greater (until the first exit provision)
- The generation owner must be the scheduling coordinator;
- The contract may not be with another scheduling coordinator that has the same parent company as the generation owner;
- The contract may not be with the same scheduling coordinator ID as the generation unit;

The first year impacts of the grandfathering provision on the market segments are shown in the figure below. Subsequent years impacts are shown in Exhibit 1, Tab “Index”. Based on this analysis the ISO believes that the grandfathering proposal is an effective and reasonable mitigation approach which imposes minimal cost impacts on other participants. With the adoption of this grandfathering approach in the draft final proposal, the ISO is eliminating the prior phase-in proposal from the 2012 GMC design.



	CRR	IOU	marketer / importer	muni	other	supplier
Proposed GMC & 100% of supply	$4.43	$126.94	$20.73	$17.40	$4.29	$21.32
Proposed GMC with Grandfather Provision	$4.43	$128.39	$20.93	$17.59	$4.33	$19.44
$ Increase (decrease) from 100% of supply to Grandfathered	$-	$1.46	$0.20	$0.19	$0.04	$(1.87)

Proposed Treatment of Transmission Ownership Rights

Under the existing GMC, Transmission Ownership Rights (TORs) are granted a discounted rate due to the limited ISO services they require. The ISO believes that TORs should continue to receive a discounted rate in the new GMC structure because this fundamental premise has not changed. The ISO is proposing to continue to provide a discounted GMC rate to TORs by:

- Exempting 100% of TOR MWhs from the Market Services charge code; and
- Applying a fixed $0.27 System Operations charge rate to TOR flow MWhs, but applying that rate only to the minimum of a Scheduling Coordinator's TOR Supply MWhs or TOR Demand MWhs (see examples below).

<u>Justification of a Discounted TOR rate</u>

The ISO first considered whether TORs should be assessed both the Market Services and System Operations charges from a cost of service standpoint. In the previous cost of service study, the ISO identified three areas in which ISO services were required for TORs:

1) Real-Time Operations: The ISO provides support on an emergency basis for flows on TORs, in a manner similar to standby service. A common method to allocate costs for standby service is in proportion to the demands placed on the system. In this case, the non-coincident peak demand of TORs was measured relative to total system demand. The resulting fraction was used to assign a percentage of the costs of Real-Time Operations to this service.
2) Scheduling: The ISO provides check-outs with neighboring Balancing Authorities in order to schedule flows across boundaries. For this service, the assignment method was to use the ratio of the total number of inter-tie schedules for TORs relative to the total number of ISO inter-tie schedules.
3) Outage Management: The ISO provides for the scheduling and coordination of outages across the Balancing Authority. The assignment method was the number of TOR transmission outages relative to total California ISO transmission outages.

ISO staff reviewed the three areas noted above from the previous cost of service study, updated the current cost of service study, and determined that TORs utilize a portion of the following ABC level 2 activities. These activities are all related to System Operations because TORs do not participate in the Market Services category. The indirect dollars were then allocated based on the direct percentage, using the process described below, to derive a total of $45.2 million in direct and indirect costs that should be allocated to TORs.

ABC Level 2 Activities	System Operations Direct Allocation (in thousands)
High level manage FNM maintenance	$ 566
Manage network applications	$ 1,249
Manage operations engineering studies	$ 1,047
Manage D+2 analysis	$ 357
Manage DA market	$ 497
Manage transmission outages	$ 1,727
Manage emergency operations	$ 327
Manage RT market - after close of market	$ 127

Manage RT operations - transmission dispatch	$ 5,264
Manage RT interchange scheduling	$ 5,247
Subtotal: TOR related direct costs	**$ 19,908**
Total Direct Costs	$ 45,923
Percentage of TORs to ABC level 2 Direct Costs	43.35%
Total Indirect Dollars	$ 58,335
Percentage of TORs indirect dollars	**$ 25,289**
Total Direct and Indirect TOR level 2 TOR costs	**$ 45,197**

Staff then allocated the ratio of TOR MWh to the total flow MWh to determine the usage percentage:

Gross Flow MWh	475,167,832
Gross TOR MWh	9,320,918
TOR as % of total flow	2.0%

The total costs related to TORs is then based on 2.0% * $45.2 million, or $0.9 million.

Collection of a Discounted TOR Rate

The cost causation detail for TORs shows that the ISO needs to collect $0.9 million from TORs. The ISO evaluated different methodologies to adjust the number of TOR MWh that would be included in the System Operations charge code. The proposal to use the minimum of supply or demand is logical because it reduces the number of billable TOR quantity to 3.3 million MWh and at the System Operations rate of $0.27 would collect revenue of $0.9 million.

Examples of the Minimum Approach for TOR Energy Flows

The ISO's proposal to charge TOR flow MWh the System Operations GMC based on the minimum of TOR supply or TOR demand is illustrated in these examples:

1) SC1: TOR supply (generation or imports) = 100 MWh, TOR demand (load or exports) = 100 MWh, TOR GMC is charged for 100 MWh.
2) SC2: TOR supply = 100 MWh, TOR demand = 60 MWh, TOR GMC is charged for 60 MWh.
3) SC3: TOR supply = 100 MWh, TOR demand = 0, TOR GMC is charged for 0 MWh.

In the case of SC2 and SC3 where there was more TOR supply than TOR demand, the excess supply would have been used to serve non-TOR demand and that demand would be charged the regular System Operations GMC rate.

Design of an Allocation Method

A method for classifying costs in any particular cost category requires two elements. The first is a metric or unit to be used as the “denominator” in the equation that converts the total cost in each category into a per unit charge. The second is a billing determinant for calculating each party’s share of the total cost in the category. The next two subsections present the ISO’s final draft proposals for each of these elements.

a. Selection of Metrics

The selection of the metrics to be used as denominators for each category was based on the guiding principles and a comparison of other ISOs’ service charges. The ISO proposes that the Market Services and System Operations GMC categories be based on gross MW per hour (capacity) and MWh (energy). This follows the guiding principles because it reflects each scheduling coordinator’s use of the ISO’s services, is flexible, transparent, easy to forecast, and simple. The ISO considered other options such as per schedule charges, energy imbalances, and peak and off peak rates. However, these alternatives are very difficult to forecast for both the ISO and market participants and it is difficult to expand the metrics to include additional market enhancements.

The Market Services category includes awarded ancillary services MW, schedules and dispatch instructions of generation, imports, load, and exports (additional detail below). As discussed during the Convergence Bidding stakeholder process, the Market Services system impact is not dependent upon whether the bid is virtual demand or virtual supply. Market Services clears offers of supply with offers of demand to award a schedule or dispatch resources. The gross MWh approach applies equal GMC costs to both participants that engaged in the trade.

The System Operations category includes all flow quantities for generation, load, imports and exports (additional detail below). The fundamental purpose of System Operations is to reliably balance supply and demand. Since both components (load and generation) are necessary to achieve balance, the ISO believes gross MWh is also appropriate for System Operations. In addition, as new technologies that shift or reduce load such as demand response, storage, and electric vehicles increase their participation in ISO markets, load will play an increasingly important role with the integration of renewable resources. Thus load may provide services similar to generation in maintaining grid reliability. Since both load and generation will provide similar services, we recommend that the GMC be designed in a manner that provides symmetrical marginal costs regardless of the technology used to provide the service. The marginal cost of the underlying technology should determine its competitiveness in the ISO market, not a difference attributed to GMC rate differential.

The CRR Services category includes the total awarded MW per hour of CRRs. Using MW per hour for ancillary services and CRRs and MWh for energy achieves simplicity in a common denominator as well as providing the flexibility to add additional MW per hour or MWh when new market enhancements and products are added. The principle of cost causation is fundamental in allocating costs to each of the administrative charge categories. The ISO believes it is appropriate to consider the relative size of beneficiaries of a category which can be accomplished by using billing determinants that accurately reflect the volume of participation. Other ISOs also utilize MW per hour and MWh as their primary quantities for creating per unit charges and billing determinants.

b. Billing Determinants

Each of the three GMC buckets and respective billing determinants are discussed in further detail below.

1. Market Services

The Market Services charge code is designed to recover costs the ISO incurs for running the markets. As such, this charge code will be applied to each scheduling coordinator's gross absolute value of awarded MWh of energy and MW per hour of ancillary services in the forward and real time markets. Specifically, the charge code will apply to the following billing determinants:

<u>Schedules and Awards (Absolute by Resource by Hour)</u>
DA Generation Schedules (including MSS)
DA Import Schedules (including MSS)
DA Load Schedules (including MSS Gross Load)
DA Export Schedules (including MSS)
DA Ancillary Service Awards
DA Ancillary Service Self Provision
Convergence Bidding Schedules
HASP Incremental and Decremental Energy (Non Dynamic)
HASP Incremental and Decremental AncillaryService Awards
HASP Incremental and Decremental Ancillary Service Self Provision
Real Time Optimal Energy
Real-Time Minimum Load Energy
Derate Energy
Real-Time Self Schedule
Real-Time Pumping Energy
Real-Time Incremental and Decremental AncillaryService Awards
Real-Time Incremental and Decremental Ancillary Service Self Provision

2. System Operations

The System Operations charge code is designed to recover costs the ISO incurs for running the grid in real time. As such, this charge code will be applied to each scheduling coordinators gross absolute value of actual real-time MWh energy flow. Specifically, the charge code will apply to the following billing determinants:

<u>Flow (Absolute by Resource by Settlement Interval)</u>
Non Dynamic System Resource Deemed Delivered Energy
Dynamic System Resource Deemed Delivered Energy
Metered Generation Quantities
Metered Default LAP Load Quantities
Metered Custom LAP Load Quantities (Including MSS Gross Load)
Metered Pumping Energy

3. CRR Services

The CRR Services charge code is designed to recover costs the ISO incurs for running the CRR markets. As such, this charge code will be applied to each scheduling coordinator's total MW holdings of CRRs that are applicable to each hour. Specifically, this charge code will apply to the following billing determinants:

CRR MWs (Absolute by Scheduling Coordinator by Financial Node)
Daily Financial Node CRR Quantity

Many of the terms utilized above are defined in the appendix to the Market Operations business process manual at the following link:

https://bpm.caiso.com/bpm/bpm/version/000000000000109

c. Administrative and Transaction Fees

There are several administrative and transaction fees which will be used in the new market design. These fees will be structured in a way that allows market participants to determine if it is economic to incur the costs associated with using the service in question while taking into consideration negative impacts to market participation if fees are too high.

1. Bid Segment Transaction Fee

The per bid segment transaction fee is designed to deter the submission of high volumes of "phishing" bids. The charge is proposed to be set at $.005 per bid segment and will be applied to all bid segments submitted. The rate of $.005 is based on a nominal charge that does not represent a significant expense to market participants under typical scheduling practices, but is enough to deter the submission of excessive bid volumes. The amount is similar to the rate used at the NYISO. The concept of a bid segment charge was raised during the Convergence Bidding stakeholder process to address concerns about bid proliferation if there was no marginal cost to place incremental bids. In addition, transaction fees collect revenue from participants who are unsuccessful in clearing the market, but who use and benefit from ISO systems and processes. The revenue from this transaction fee will offset costs recovered through Market Services. Thus, if the number of unsuccessful bids increases, the Market Services rate for those participants who cleared the market will be reduced.

2. CRR Bid Transaction Fee

The CRR bid transaction fee is designed to recover a portion of the CRR costs on a transactional basis. The fee will apply to the CRR nomination and allocation processes. The rate of $1.00 will be used for this fee. The revenue from this transaction fee will offset costs recovered through CRR Services. Thus if the number of unsuccessful bids increases, the CRR services rate for those participants who cleared the market will be reduced. A number of stakeholders commented that their understanding was that IFM and convergence bids will be charged $0.005. To clarify, the price unit is $0.005 per bid segment with a limit of 10 bid segments so bids can have a maximum charge of $0.05 per bid. In contrast, the ISO's CRR GMC proposal is $1 per nomination or per bid (without consideration of the number of segments). Furthermore IFM and convergence bids are accepted for 24 hours per day for each day of the month. CRR nomination tiers and auctions are divided into two time-of-use (TOU) periods per month.

Contrasting IFM bids and CRR nominations on a comparable basis, the $1 per CRR nomination is on the same order as $0.005 per bid segment. For example, to bid 100 MW into the IFM for 744 hours in any given (31 day) month would cost a minimum of:

- IFM charge = 1 bid segment/hour x $0.005/bid segment x 744 hours = $3.72

To receive 100 MW CRR for 744 hours in any given (31 day) month would require two nominations: one for On Peak and one for Off Peak.

- Proposed CRR GMC = 2 nominations x $1/nomination = $2.00

The analysis above shows that a $1 per nomination fee for CRR is comparable to $0.005 per bid segment for IFM bids and convergence bids.

Inter-SC Trade Transaction Fee

The inter-SC trade transaction fee is designed to recover costs directly related to the scheduling and settling of inter-SC trades. The revenue from this transaction fee will offset costs recovered through Market Services. The ISO determined a rate (slightly less than the current rate), as an appropriate level so as not to deter existing activity, but also to recognize that without any transaction cost this could increase the demand for the service and drive costs higher. A fee of $1.00 per inter-SC trade (each side of trade) will apply to the following billing determinants:

<u>INTER-SC Trade (Absolute by Trade)</u>
DAM TO-SC Inter-SC Trade Energy (Physical and Converted)
DAM FROM-SC Inter-SC Trade Energy (Physical and Converted)
DAM TO-SC Inter-SC Trade Energy (Financial)
DAM FROM-SC Inter-SC Trade Energy (Financial)
HASP TO-SC Inter-SC Trade Energy (Physical and Converted)
HASP FROM-SC Inter-SC Trade Energy (Physical and Converted)
HASP TO-SC Inter-SC Trade Energy (Financial)
HASP FROM-SC Inter-SC Trade Energy (Financial)
Ancillary Services TO-SC Inter-SC Trade Energy
Ancillary Services FROM-SC Inter-SC Trade Energy
RUC Obligation TO-SC Inter-SC Trade Energy

3. <u>SCID Administrative Fee</u>

The SCID administrative fee is designed to limit the number of SCIDs to those needed for legitimate business purposes in order to reduce the additional burden on the ISO systems and resources that an unlimited number of SCIDs could create. The ISO proposes to keep the charge at the current $1,000 per month per SCID and only apply the charge to SCs that have settlements activity in a trade month. The revenue from this transaction fee will offset costs recovered through Market Services.

Elimination of the Station Power fee

ISO staff has reviewed the station power fee and concluded that it should not be a separate GMC charge. The amount is insignificant and the full costs are included in the System Operations charge code.

Metered Sub System Load Following Energy

The ISO has determined that it is appropriate to exclude MSS Load Following instructed imbalance energy from the Market Services GMC charge. This energy quantity reflects the MSS's performance of its real-time load following function, and the cost causation impacts of this function are appropriately recovered through the System Operations charge.

Other Issues

ISO staff reviewed other issues raised by stakeholders and has decided not to make changes to the proposal.

Unscheduled Energy

There was discussion to extend the Market Services charge to apply to energy delivered in real time that is not scheduled or in response to ISO dispatch instructions. ISO staff has determined that RT delivered energy does get an appropriate share of costs through the System Operations GMC charge (which includes a significant share of the cost of the ISO's settlement process) and therefore satisfies the principle of cost causation. In accordance with guiding principle 2 stated earlier in this paper, the GMC should focus on recovering the costs associated with using ISO services and should not try to address market participant behavior. In the case of unscheduled or undispatched energy flows, there are market rules that already address uninstructed deviations such as exposure to real time prices and ineligibility for bid cost recovery. In addition, the ability to avoid ISO market processes (i.e. a participant's failure to submit supply bids), is limited by must offer obligations for RA resources. The ISO has therefore decided not to apply a Market Services GMC charge to real-time deviations.

PIRP Forecast Fee

There has been discussion whether to include a separate charge for PIRP forecast fees. This question is being addressed in the ISO's Renewable Integration Market and Product Review initiative and will be resolved in that stakeholder process. If the PIRP forecast fee is retained, it will be treated for GMC purposes like the other special fees in this proposal, as an offset to the total costs to be recovered through one or more of the other cost categories.

Revenue Requirement Cap Proposal

The last component of the GMC redesign for 2012 is to establish a new revenue requirement cap. The previous cap was set at $195 million in 2004 and increased to $197 million in 2006. One year extensions of the revenue requirement cap and current GMC rate design have been approved for each year thereafter, including 2011. In the January 13 straw proposal modifications, the ISO proposed a revenue requirement cap that would remain in place for five years and would increase by 1% each year beginning in 2013. Stakeholders responded by raising concerns about a long term rate ceiling given the economic uncertainties facing the state, the industry, and public power agencies. In response to stakeholder concerns, the ISO proposes to shorten the length of the revenue requirement period to three years, (which extends to the end of the 2008 bonds), and at which time stakeholders will have more certainty about the future. Additionally a revenue cap escalator appears unacceptable. Thus, the ISO proposes a three year revenue requirement cap with $197 million as the baseline in 2012. The cap will be then be increased once in 2013 to $199 million and remain at that level for 2013 to 2014. The annual revenue requirement cap based on this structure over the three year period would be:

Year	Revenue Requirement Cap
2012	$197,000,000
2013	$199,000,000
2014	$199,000,000

The ISO proposes to retain the same process currently included in the tariff with respect to the revenue requirement cap so that as long as the ISO's annual budget for each year does not exceed that year's revenue requirement cap, and there are no GMC rate design or billing determinant modifications proposed for the next year, the ISO will not be required to make a section 205 with FERC seeking approval for the next year's revenue requirement.

The current budget approval stakeholder process will remain in the tariff, and that process culminates with each annual budget being presented to the ISO Board for approval at the December Board meeting and posted on the ISO website after approval. The ISO's proposed revenue requirement caps, would "sunset" on December 31, 2014 and the ISO would be required to make a 205 filing for the GMC that would become effective on January 1, 2015.

Examples of GMC Charges by Activity

The following are examples of the GMC charges that would be incurred for various activities utilizing the grandfathering approach, using hypothetical estimated rates based on historical data. Please note that the SCID fee of $1,000 per month would apply to all activities listed below in addition to the individual transaction charges. Also note that the Market Services rate does not take into account the expected volume for convergence bidding. The ISO estimates that the additional volume of convergence bids would reduce the market services rate to $.082. The GMC rates used in the calculations are based on the rates provided in the grandfathering revised data set:

Market Services Rate: $0.091368

System Operations Rate: $0.29216

System Operations TOR Rate: $0.27

CRR Services Rate: $0.011318

Bid Segment Rate: $0.005

Inter SC Trade fee: $1.00

CRR Bid Segment Transaction fee: $1.00

1. **<u>Generation</u>**

Scenario: A generator submits a 4-segment energy bid in the day-ahead market and is scheduled for 100 MWh. The generator then submits a 4-segment energy bid to the real-time market and is decremented 10 MWh. Its real-time metered flow is measured at 90 MWh.

GMC charges would be:

Market Services Charge (day-ahead schedule and real-time instructions): 110 MWh * $0.091368 = $10.05

System Operations Charge (real-time metered flow): 90 MWh * $0.29216 = $26.29

Bid Segment Fee: 8 * $0.005 = $.04

Total: $36.38

2. Ancillary Services (1)

Scenario 1: A generator submits an AS bid and is awarded 50 MW operating reserves in the day-ahead market for hour ending 9. No contingency event occurs in hour ending 9.

GMC charges would be:

Market Services Charge (day-ahead and real-time schedules): 50 MW h * $0.091368 = $4.57

Bid Segment Fee: 1 * $0.005 = $0.005

Total: $4.58

3. Ancillary Services (2)

Scenario 2: A generator submits an AS bid and is awarded 50 MW operating reserve in the day ahead market for hour ending 9. The generator then submits a 4-segment energy bid in the real-time market and a contingency event occurs in hour ending 9 resulting in 50 MWh energy dispatch for 15 minutes.

GMC charges would be:

Market Services Charge: 50 MW h * $0.091368 = $4.57

System Operations Charge: (50 MWh / 4) * $0.29216 = $3.65

Bid Segment Fee: 5 * $0.005 = $.03

Total: $8.25

4. Load

Scenario: Load self schedules 100 MWh in the day ahead market and its meter data shows that it consumed 100 MWh in real time.

GMC charges would be:

Market Services Charge: 100 MWh * $0.091368 = $9.14

System Operations Charge: 100 MWh * $0.29216 = $29.22

Bid Segment Fee: 1 * $0.005 = $0.005

Total: $38.36

5. Imports

Scenario: An importer submits a 4-segment energy bid in the day-ahead market and is scheduled for 100 MWh. The importer then submits a 2-segment energy bid to the real-time market and is inc'd 10 MWh in HASP. The 110 MWh import schedule is then deemed delivered in real-time based on the final e-tag for the transaction.

GMC charges would be:

Market Services Charge: 110 MWh * $0.091368 = $10.05

System Operations Charge: 110 MWh * $0.29216 = $32.14

Bid Segment Fee: 6 * $0.005 = $0.03

Total: $42.22

6. Exports

Scenario: An exporter submits a 4-segment energy bid in the day-ahead market and is scheduled for 100 MWh. The exporter then submits a 6-segment energy bid to the real-time market and is dec'd 10 MWh in HASP. The 90 MWh export schedule is then deemed delivered in real-time based on the final e-tag for the transaction.

GMC charges would be:

Market Services Charge: 110 MWh * $0.091368 = $10.05

System Operations Charge: 90 MWh * $0.29216 = $26.29

Bid Segment Fee: 10 * $0.005 = $.05

Total: $36.39

7. Convergence Bidder

Scenario: A convergence bidder submits a 10-bid segment virtual demand bid in the day-ahead market for 100 MWh.

GMC charges would be:

Market Services Charge: 100 MWh * $0.091368 = $9.14

System Operations Charge: $0.00 (there is no real-time energy flow associated with virtual bids)

Bid Segment Fee: 10 * $0.005 = $.05

Total: $9.19

8. Inter-SC Trade

Scenario: Scheduling Coordinator A schedules an inter-SC trade with Scheduling Coordinator B for 100 MWh.

GMC charges would be (for both Scheduling Coordinators A and B):

Inter SC Trade Fee: 1 * $1.00 = $1.00

Total: $1.00 (each)

9. CRRs

Scenario 1: A Scheduling Coordinator bids and is awarded 100 MW CRR on peak or a LSE nominates and is allocated 100 MW CRR on peak during the October 2010 monthly process.

GMC charges would be:

CRR Bid or Nomination Fee = 1 * $1.00 = $1.00

CRR Charge: (100 MW * 416 hours) * $0.011318 = $470.83

Total: $471.83

Scenario 2: A Scheduling Coordinator bids and is awarded 100 MW CRR on peak or a LSE nominates and is allocated 100 MW CRR on peak through the annual process and holds the CRR for all months of the year. Note that the number of hours in a month will be dependent upon the NERC calendar. The GMC costs will be accrued monthly over the year. We utilized October 2010 as a proxy to simplify the example:

GMC charges would be:

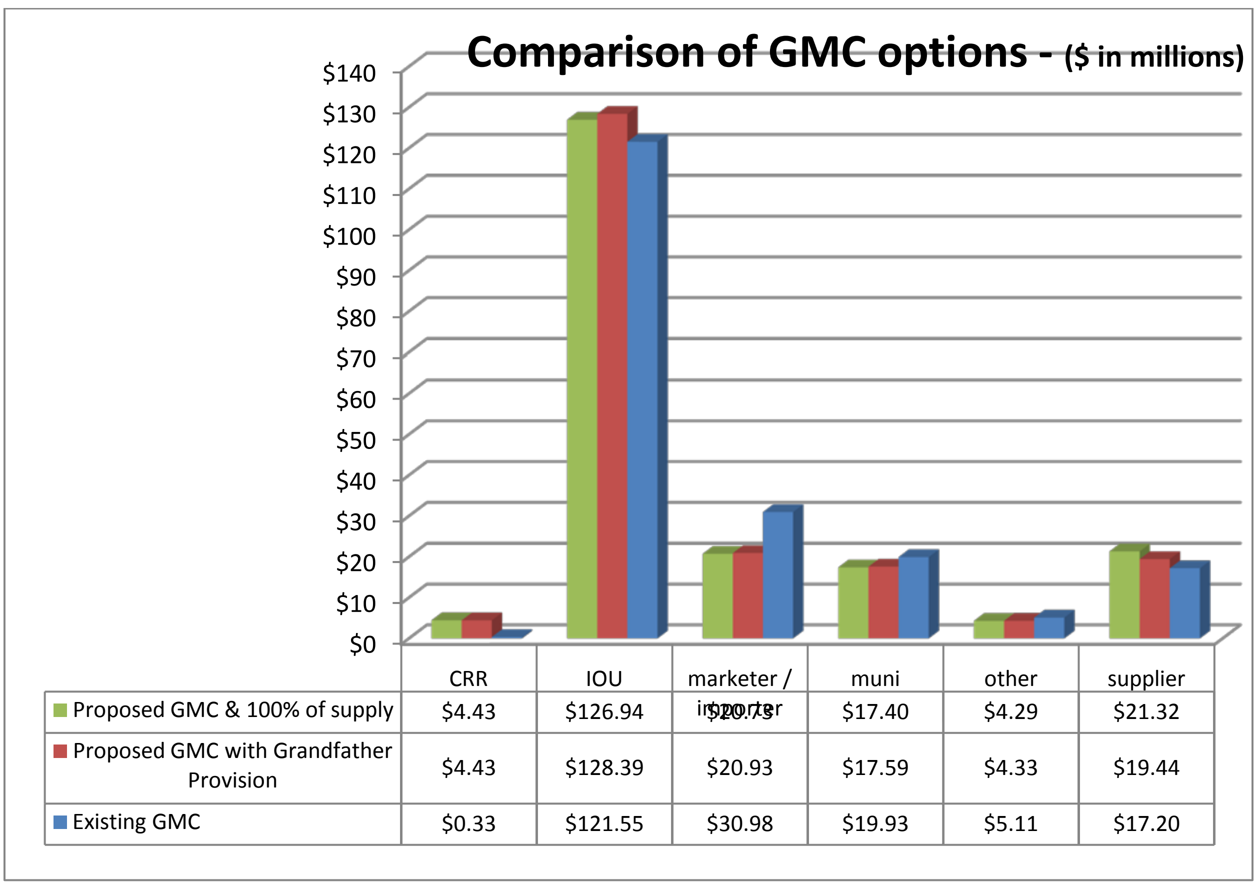
CRR Bid Fee = 1 * $1.00 = $1.00

CRR Charge: (100 MW * 416 hours) * $0.011318 = $470.83 per month

Total: $5,650.95

Bill Impacts

The ISO provided bill impact studies by SCID to market participants for the original GMC rate design as well as the draft final proposal. To provide estimates of the impacts of the new structure, the ISO developed hypothetical billing rates using the 2010 budget amount and allocated those dollars to charge categories based on the process described in the discussion paper. The billing determinants used to calculate the rates came from market data from the period of June 1, 2009 to May 31, 2010. The ISO has applied the rates for each charge code to each SCID's volumes using the billing determinants listed above to determine the costs they would have been charged if the new GMC structure had been in place. The ISO has communicated individual SCID information to those SCs who have requested the information. The graph below illustrates the overall impact analysis by customer type:



	CRR	IOU	marketer / importer	muni	other	supplier
Proposed GMC & 100% of supply	$4.43	$126.94	$20.73	$17.40	$4.29	$21.32
Proposed GMC with Grandfather Provision	$4.43	$128.39	$20.93	$17.59	$4.33	$19.44
Existing GMC	$0.33	$121.55	$30.98	$19.93	$5.11	$17.20

Next Steps

The 2012 GMC Cost of Service Study will continue with the following timeline:

- February 22, 2011 – Conference call with Stakeholders to review draft final proposal
- March 1, 2011 – Stakeholder comments on draft final proposal due
- March 30-31, 2011 – ISO will present GMC proposal to Board for approval
- April 2011- Proposed tariff language will be provided for stakeholder review
- May 2011 – Proposed tariff amendments implementing revised GMC structure filed with FERC

Proposed GMC
Grandfather 100% of specific generation in System Operations
Comparison Period Jun-09 to May-10

California ISO
Shaping a Renewed Future

Options

Proposed GMC — The current proposal uses gross generation, imports, load & export MWs for both market services & system operations. It eliminates MSS load following MWh from Market Services. Modify TORs as follows: 100% of TOR volumes excluded from market services and systems operations; minimum of TOR volumes for supply or demand are charged a fixed rate of $0.27 per MWh. New CRR volumes have been pulled as there were errors in the prior bill comparison.

Proposed modifications — Exclude 100% of generation from system operations meeting the following criteria

Grandfather criteria — The contract precludes the supplier from recovering the additional GMC costs under the 2012 design from the buyer; the contract must have been executed prior to 1/1/11; the duration of the contract must be three years or greater (until the first exit provision); generator owner must be the scheduling coordinator for the unit; the contract may not be with another scheduling coordinator that has the same parent company as the generation owner; and the contract may not be with the same scheduling coordinator ID as the generation unit resides.

Billing Determinants

Awards — MWs of awarded bids used for market services

Flows — MWs of metered flow used for system operations

Excluded data — The individual data for the scids comprising the seven largest scs have been deleted. However the totals have not been changed.

Calculation of rates

Equalizes 2010 revenue requirement to actual for the June 2009 - May 2010 period.
Allocates revenue requirement to 3 cost categories
Credits Market bid fee, Inter-SC trade fee and SCID charges to the market services cost category.
Credits CRR auction bid fee to the CRR cost category.
Excludes MSS Load following from Market services
Excludes TORs from Market services and system operations
Charges minimum of supply or demand for TORs a fixed rate of $0.27 per MWh
Credits TOR revenue to the system operations cost category.
Grandfathers contracts - excludes 100% of specified generation contracts meeting defined criteria from system operations volumes
Phases in of supply refers to earlier proposal to phase into system operation 1/3 of supply in in year 1, 2/3 in year 2 and 100% in year 3
Divides the 3 cost categories by the billing determinants to derive the rates.

Rate Comparisons

	Include 100% of supply	Grandfathering of units					Phase-In of Supply	
		2012-14	2015	2016	2017	2018-21	1/3 in 2012	2/3 in 2013
Market bid fee	$ 0.005	$ 0.005	$ 0.005	$ 0.005	$ 0.005	$ 0.005	$ 0.005	$ 0.005
Inter-SC trade Fee	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00
CRR auction bid fee	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00
SCID monthly fee	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000
Market services rate per MWh	$ 0.0914	$ 0.0914	$ 0.0914	$ 0.0914	$ 0.0914	$ 0.0914	$ 0.0914	$ 0.0914
Systems Operations rate per MWh	**$ 0.2876**	**$ 0.2922**	**$ 0.2920**	**$ 0.2913**	**$ 0.2907**	**$ 0.2901**	**$ 0.4328**	**$ 0.3455**
TOR rate per MWh	$ 0.2700	$ 0.2700	$ 0.2700	$ 0.2700	$ 0.2700	$ 0.2700	$ 0.2875	$ 0.2875
CRR services rate per MWh	$ 0.0113	$ 0.0113	$ 0.0113	$ 0.0113	$ 0.0113	$ 0.0113	$ 0.0113	$ 0.0113
Excluded supply/generation - TWh	-	7.23	6.68	5.69	4.71	3.72	156.38	78.19

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Grandfathering

GF rates — Rates based on proposed GMC after modification for TORs, MSS and exclude 100% of suppliers generation

GF contracts by year — Summary by year of grandfathered contracts to be excluded from system operations

Proposed GMC
Grandfather 100% of specific generation in System Operations
Comparison Period Jun-09 to May-10

	100% supply
100% supply rates	Rates based on proposed GMC after modification for TORs and phase-in of 100% supply in system operations
TORs	Shows total TORs by scid and generation, imports, load and exports. Calculates the TOR adjustment
	Existing GMC units and amounts
Actual units by CC by baid	Shows actual GMC units by SCID and charge code for the period June 2009 to May 2010
Actual dollars by CC by baid	Shows actual GMC dollar amounts by SCID and charge code for the period June 2009 to May 2010
data details	Components to GMC graphs by customer class

Listing of Billing Determinants

Market Services

Schedules and Awards (Absolute by RSRC)	Included
DA Generation Schedules (including ETC TOR)	YES
DA Import Schedules (including ETC TOR)	YES
DA Load Schedules (including ETC TOR)	YES
DA Export Schedules (including ETC TOR)	YES
DA Ancillary Service Awards	YES
DA Ancillary Service Self Provision	YES
Convergence Bidding Schedules	YES
MSS Gross MWh (including ETC TOR)	YES
RUC Awards	NO
WHEEL Quantities (One-Side)	YES
DA Inter-SC Trade	NO
HASP Incremental and Decremental Energy (Non Dynamic)	YES
HASP Incremental and Decremental Ancillary Service Awards	YES
HASP Incremental and Decremental Ancillary Service Self Provision	YES
HASP Inter-SC Trades	NO
HASP Incremental and Decremental Wheel (One-sided)	YES
HASP Operational Adjustment	NO
Real Time Optimal Energy	YES
Residual Imbalance Energy	NO
Real-Time Minimum Load Energy	YES
Exceptional Dispatch Energy	NO
Regulation Energy	NO
Standard Ramping Energy	NO
Ramping Energy Deviation	NO
Derate Energy	YES
Real-Time Self Schedule	YES
MSS Load Following	YES
Real Time Pumping Energy	YES
Real Time Operational Adjustments	NO
Real Time Incremental and Decremental Ancillary Service Awards	YES
Real Time Incremental and Decremental Ancillary Service Self Provision	YES

System Operations

Flow (Absolute by RSRC)	Included
Non Dynamic System Resource Deemed Deliver Energy (include ETC/TOR)	Yes
Dynamic System Resource Deemed Deliver Energy (include ETC/TOR)	Yes
Metered Generation Quantities (include ETC/TOR)	Yes

Proposed GMC
Grandfather 100% of specific generation in System Operations
Comparison Period Jun-09 to May-10

Metered Default Lap Quantities (include ETC/TOR)	Yes
Metered Custom Lap Quantities (include ETC/TOR)	Yes
Metered Pumping Energy (include ETC/TOR)	Yes
MSS Gross Metered Quantizes (include ETC/TOR)	Yes
Non Dynamic System Resource Wheel Deemed Deliver Energy (one sided)	Yes

Inter-SC Trades

INTER-SC Trade (Absolute by Trade)	**Included**
DAM TO-SC Inter-SC Trade Energy (Physical and Converted)	Yes
DAM FROM-SC Inter-SC Trade Energy (Physical and Converted)	Yes
DAM TO-SC Inter-SC Trade Energy (Financial)	Yes
DAM FROM-SC Inter-SC Trade Energy (Financial)	Yes
HASP TO-SC Inter-SC Trade Energy (Physical and Converted)	Yes
HASP FROM-SC Inter-SC Trade Energy (Physical and Converted)	Yes
HASP TO-SC Inter-SC Trade Energy (Financial)	Yes
HASP FROM-SC Inter-SC Trade Energy (Financial)	Yes
Ancillary Services TO-SC Inter-SC Trade Energy	Yes
Ancillary Services FROM-SC Inter-SC Trade Energy	Yes
RUC Obligation TO-SC Inter-SC Trade Energy	Yes
RUC Obligation FROM-SC Inter-SC Trade Energy	Yes

Proposed GMC modified for TORs
Grandfather 100% of specific generation contracts in System Operations
Comparison Period Jun-09 to May-10

Revised GMC Rates

Units Jun-09 to May-10	Market Service rate (Award)	Systems Operations rate (Flow)	Flow TORs	CRR (revised volumes)	CRR auction bid fee	Market bids	ISC Trades	SCIDs
Gross volumes	519,946,950	475,167,832	-	591,726,863				
TOR modification	(9,276,859)	(5,967,482)	-	-				
Transfer TORs to separate category	-	(3,353,436)	3,353,436	-				
Exclude Suppliers generation	-	(7,227,000)	-	-				
Exclude MSS load following	(128,315)	-	-	-				
Additional CRR volumes	-	-	-	24,638,375				
Net volumes	510,541,777	458,619,915	3,353,436	616,365,238				
Number of CRR auction bids					480,276			
Number of market bids						26,893,996		
Number of Inter-SC trades							3,854,538	
Number of SCIDs								177
Rate per TOR			$ 0.27					
Fee per market bid						$ 0.005		
Fee per CRR auction bid					$ 1.00			
Monthly SCID fee								$ 1,000
Annual SCID fee								$ 12,000
Fee per Inter-SC trade							$ 1.00	
Fee and charge revenue			$ 905,428		$ 480,276	$ 134,470	$ 3,854,538	$ 2,124,000

Rates for Year 1	Market Service rate (Award)	Systems Operations rate (Flow)	Flow TORs	CRR	CRR auction bid fee	Market bids	ISC Trades	SCIDs	Total
Revenue Requirement 2010	**$ 52,756,000**	**$ 134,883,000**	**$ -**	**$ 7,456,000**					**$ 195,095,000**
Actual GMC collected									195,110,642
Difference									(15,642)
% of revenue requirement	27%	69%	0%	4%	0%	0%	0%	0%	100%
Revenue Requirement	$ 52,756,000	$ 134,883,000	$ -	$ 7,456,000		$ -			$ 195,095,000
Adjust Revenue requirement to actual	$ 4,230	$ 10,814	$ -	$ 598	$ -	$ -	$ -	$ -	$ 15,642
Adjusted revenue requirement	$ 52,760,230	$ 134,893,814	$ -	$ 7,456,598	$ -	$ -	$ -	$ -	$ 195,110,642
Allocate TORs	$ -	$ (905,428)	$ 905,428	$ -	$ -	$ -	$ -	$ -	$ -
Allocate market bid fees	$ (134,470)	$ -	$ -	$ -	$ -	$ 134,470	$ -	$ -	$ -
Allocate CRR bid fees	$ -	$ -	$ -	$ (480,276)	$ 480,276	$ -	$ -	$ -	$ -
Allocate SCID fee	$ (3,854,538)	$ -	$ -	$ -	$ -	$ -	$ 3,854,538	$ -	$ -
Allocate inter-SC trade fee	$ (2,124,000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,124,000	$ -
Revenue requirement for rates	**$ 46,647,222**	**$ 133,988,386**	**$ 905,428**	**$ 6,976,322**	**$ 480,276**	**$ 134,470**	**$ 3,854,538**	**$ 2,124,000**	**$ 195,110,642**
Volume Jun-09 to May-10	**510,541,777**	**458,619,915**	**3,353,436**	**616,365,238**	**480,276**	**26,893,996**	**3,854,538**	**177**	
Rates	**$ 0.091368**	**$ 0.29216**	**$ 0.27**	**$ 0.011318**	**$ 1.00**	**$ 0.005**	**$ 1.00**	**$12,000**	

Summary of Volumes for Year 1	Generation	Imports	Load	Exports	Total Volume	Separate TOR category
Market Services - Awards						
Gross volumes	201,028,000	81,946,538	227,791,195	9,181,218	519,946,950	-
Exclude TORs	(1,180,919)	(4,569,078)	(247,263)	(3,279,599)	(9,276,859)	-
Exclude MSS load following	(129,582)	731	511	25	(128,315)	
Net volumes	**199,717,499**	**77,378,191**	**227,544,442**	**5,901,645**	**510,541,777**	**-**
	-	-	-	-	-	-
System Operations - Flows						
Gross volumes	170,925,422	69,416,225	226,000,481	8,825,705	475,167,832	-
Exclude TORs	(1,180,919)	(4,591,246)	(195,318)	-	(5,967,482)	
Transfer TORs to separate category	-	-	(51,946)	(3,301,490)	(3,353,436)	3,353,436
Exclude 100% of grandfathered generation	(7,227,000)	-	-	-	(7,227,000)	-
Net volumes	**162,517,503**	**64,824,979**	**225,753,217**	**5,524,215**	**458,619,915**	**3,353,436**

Qualifying contract details by year

Qualifying contract criteria
The contract precludes the supplier from recovering the additional GMC costs under the 2012 design from the buyer
The contract must have been executed prior to 1/1/11
The duration of the contract must be three years or greater (until the first exit provision)
The generator owner must be the scheduling coordinator for the unit
The contract may not be with another scheduling coordinator that has the same parent company as the generation owner
The contract may not be with the same scheduling coordinator ID as the generation unit resides
Provision only applies to exempt System Operations charge

annual MWhs	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
7,227,000	7,227,000	7,227,000	7,227,000	6,679,500	5,694,000	4,708,500	3,723,000	3,723,000	3,723,000	3,723,000

100% supply rate

Proposed GMC modified for TORs
No grandfathering of supply - 100% included in systems operations
Comparison Period Jun-09 to May-10

Revised GMC Rates

Units Jun-09 to May-10	Market Service rate (Award)	Systems Operations rate (Flow)	Flow TORs	CRR (revised volumes)	CRR auction bid fee	Market bids	ISC Trades	SCIDs
Gross volumes	519,946,950	475,167,832	-	591,726,863				
TOR modification	(9,276,859)	(9,320,918)	-	-				
Transfer TORs to separate category	-	(3,353,436)	3,353,436					
Additional CRR volumes	-	-	-	24,638,375				
Exclude MSS load following	(128,315)	-	-					
Net volumes	510,541,777	465,846,915	3,353,436	616,365,238				
Number of CRR auction bids					480,276			
Number of market bids						26,893,996		
Number of Inter-SC trades							3,854,538	
Number of SCIDs								177
Rate per TOR			$ 0.27					
Fee per market bid						$ 0.005		
Fee per CRR auction bid					$ 1.00			
Monthly SCID fee								$ 1,000
Annual SCID fee								$ 12,000
Fee per Inter-SC trade							$ 1.00	
Fee and charge revenue			$ 905,428		$ 480,276	$ 134,470	$ 3,854,538	$ 2,124,000

Rates	Market Service rate (Award)	Systems Operations rate (Flow)		CRR	CRR auction bid fee	Market bids	ISC Trades	SCIDs	Total
Revenue Requirement	**$ 52,756,000**	**$ 134,883,000**	**$ -**	**$ 7,456,000**					**$ 195,095,000**
Actual									195,110,642
Difference									(15,642)
% of revenue requirement	27%	69%	0%	4%	0%	0%	0%	0%	100%
Revenue Requirement	$ 52,756,000	$ 134,883,000		$ 7,456,000		$ -			$ 195,095,000
Adjust Revenue requirement to actual	$ 4,230	$ 10,814		$ 598	$ -	$ -	$ -	$ -	$ 15,642
Adjusted revenue requirement	$ 52,760,230	$ 134,893,814		$ 7,456,598	$ -	$ -	$ -	$ -	$ 195,110,642
Allocate TORs	$ -	$ (905,428)	$ 905,428						
Allocate market bid fees	$ (134,470)	$ -	$ -	$ -	$ -	$ 134,470	$ -	$ -	$ -
Allocate CRR bid fees	$ -	$ -	$ -	$ (480,276)	$ 480,276	$ -	$ -	$ -	$ -
Allocate SCID fee	$ (3,854,538)	$ -	$ -	$ -	$ -	$ -	$ 3,854,538	$ -	$ -
Allocate inter-SC trade fee	$ (2,124,000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,124,000	$ -
Revenue requirement for rates	**$ 46,647,222**	**$ 133,988,386**	**$ 905,428**	**$ 6,976,322**	**$ 480,276**	**$ 134,470**	**$ 3,854,538**	**$ 2,124,000**	**$ 195,110,642**
Volume Jun-09 to May-10	**510,541,777**	**465,846,915**	**3,353,436**	**616,365,238**	**480,276**	**26,893,996**	**3,854,538**	**177**	
Rates	**$ 0.091368**	**$ 0.287623**	**$ 0.27**	**$ 0.011318**	**$ 1.00**	**$ 0.005**	**$ 1.00**	**$12,000**	

Summary of Volumes for Year 3	Generation	Imports	Load	Exports	Total Volume	Separate TOR category
Market Services - Awards						
Gross volumes	201,028,000	81,946,538	227,791,195	9,181,218	519,946,950	-
Exclude TORs	(1,180,919)	(4,569,078)	(247,263)	(3,279,599)	(9,276,859)	-
Exclude MSS load following	(129,582)	731	511	25	(128,315)	
Net volumes	**199,717,499**	**77,378,191**	**227,544,442**	**5,901,645**	**510,541,777**	**-**
	-	-	-	-	-	-
System Operations - Flows						
Gross volumes	170,925,422	69,416,225	226,000,481	8,825,705	475,167,832	-
Exclude TORs	(1,180,919)	(4,591,246)	(195,318)	-	(5,967,482)	-
Transfer TORs to separate category	-	-	(51,946)	(3,301,490)	(3,353,436)	3,353,436
Net volumes	**169,744,503**	**64,824,979**	**225,753,217**	**5,524,215**	**465,846,915**	**3,353,436**

Proposed GMC with adjustment for TORs

TOR analysis	Reported volumes				
	Generation	Imports	Load	Exports	Total
	1,180,919	4,591,246	247,263	3,301,490	9,320,918

Flows - include minimum (or exclude maximum) of supply or demand				
Generation	Imports	Load	Exports	Total
(1,180,919)	(4,591,246)	(195,318)	-	(5,967,482)

Flow Billable quantity				
Generation	Imports	Load	Exports	Total
-	-	51,946	3,301,490	3,353,436

Award - exclude all units				
Generation	Imports	Load	Exports	Total
1,180,919	4,569,078	247,263	3,279,599	9,276,859

Summary of actual GMC billing determinants Jun-09 to May-10	Monthly		Daily											Monthly	
	4501	4502	4503	4505	4506	4508	4511	4512	4513	4534	4535	4536	4537	4546	4575
	peak demand	off peak demand	exports	metered load	uninstructed imbalance energy (UIE) MWh	metered load on TORs	# of hourly schedules	# of hourly trades	PG&E trades	DA, HA & RT AS - MW	instructed energy MWh	UIE MWh	Max of supply or demand in DA	PIRP UIE MWh	monthly SCID charge
Total units	421,787	18,357	5,568,907	231,329,854	9,869,301	5,906,236	5,575,498	3,863,740	-	35,346,186	31,262,387	9,869,301	86,897,500	45,928	1,889

actual $ by cc by baid

Summary of actual GMC $ Amounts Jun-09 to May-10	Monthly		DAILY											Monthly		Total	
	4501	4502	4503	4505	4506	4508	4511	4512	4513	4534	4535	4536	4537	4546	4575		Station Power
	peak demand	off peak demand	exports	metered load	uninstructed imbalance energy (UIE) MWh	metered load on TORs	# of hourly schedules	# of hourly trades	PG&E trades	DA, HA & RT AS - MW	instructed energy MWh	UIE MWh	Max of supply or demand in DA	PIRP UIE MWh	monthly SCID charge		
Total $ amount	30,881,248	891,603	5,665,966	70,695,820	10,907,910	816,724	8,904,327	6,012,732	-	14,179,875	14,209,685	4,205,679	25,813,211	71,864	1,854,000	195,110,642	101,600

Proposed GMC Options

Comparison of $ amounts						
Customer Class	Existing GMC	Proposed GMC w/ 100% of supply	Proposed GMC w/ grandfathering	Increase (decrease) 100% supply over existing GMC	Increase (decrease) grand- fathering over existing GMC	Increase (decrease) grand- fathering over 100% supply
CRR	$ 329,611	$ 4,427,533	$ 4,428,678	$ 4,097,923	$ 4,099,067	$ 1,145
marketer / importer	$ 30,984,042	$ 20,729,511	$ 20,934,781	$ (10,254,531)	$ (10,049,261)	$ 205,270
muni	$ 19,931,172	$ 17,401,830	$ 17,585,756	$ (2,529,342)	$ (2,345,416)	$ 183,926
Other	$ 5,112,170	$ 4,291,107	$ 4,333,441	$ (821,063)	$ (778,728)	$ 42,334
supplier	$ 17,199,407	$ 21,315,501	$ 19,435,893	$ 4,116,094	$ 2,236,486	$ (1,879,608)
IOU	$ 121,554,240	$ 126,944,719	$ 128,391,924	$ 5,390,479	$ 6,837,684	$ 1,447,205
Total	**$ 195,110,642**	**$ 195,110,202**	**$ 195,110,474**	**$ (441)**	**$ (168)**	**$ 273**

Customer Class	Market Services	System Operations	CRRs	Fees & charges	Total
Components of Charges - 100% of supply					
CRR	$ 23,242	$ 72,631	$ 3,880,718	$ 450,943	$ 4,427,533
marketer / importer	$ 5,094,895	$ 13,091,783	$ 441,302	$ 2,101,530	$ 20,729,511
muni	$ 4,136,424	$ 11,882,649	$ 224,557	$ 1,158,199	$ 17,401,830
Other	$ 883,480	$ 2,686,156	$ 67,889	$ 653,582	$ 4,291,107
supplier	$ 5,155,495	$ 14,708,166	$ 51,388	$ 1,400,452	$ 21,315,501
IOU	$ 31,353,644	$ 92,452,331	$ 2,310,168	$ 828,576	$ 126,944,719
Total	**$ 46,647,181**	**$ 134,893,715**	**$ 6,976,022**	**$ 6,593,284**	**$ 195,110,202**
Components of Charges - grandfathering					
CRR	$ 23,242	$ 73,775	$ 3,880,718	$ 450,943	$ 4,428,678
marketer / importer	$ 5,094,895	$ 13,297,053	$ 441,302	$ 2,101,530	$ 20,934,781
muni	$ 4,136,424	$ 12,066,575	$ 224,557	$ 1,158,199	$ 17,585,756
Other	$ 883,480	$ 2,728,490	$ 67,889	$ 653,582	$ 4,333,441
supplier	$ 5,155,495	$ 12,828,558	$ 51,388	$ 1,400,452	$ 19,435,893
IOU	$ 31,353,644	$ 93,899,536	$ 2,310,168	$ 828,576	$ 128,391,924
Total	**$ 46,647,181**	**$ 134,893,987**	**$ 6,976,022**	**$ 6,593,284**	**$ 195,110,474**
Increase (Decrease) grandfathering from 100% of supply					
CRR	$ -	$ 1,145	$ -	$ -	$ 1,145
marketer / importer	$ -	$ 205,270	$ -	$ -	$ 205,270
muni	$ -	$ 183,926	$ -	$ -	$ 183,926
Other	$ -	$ 42,334	$ -	$ -	$ 42,334
supplier	$ -	$ (1,879,608)	$ -	$ -	$ (1,879,608)
IOU	$ -	$ 1,447,205	$ -	$ -	$ 1,447,205
Total	**$ -**	**$ 273**	**$ -**	**$ -**	**$ 273**

Proposed GMC Options

Comparison of Volumes							
Customer Class	**Awards**	**Flows 100% of supply**	**Flows with grand-fathering**	**CRRs**	**CRR auction bids**	**Market bids**	**ISC Trades**
CRR	254,379	252,520	252,520	342,880,161	231,258	1,038	3,680
marketer / importer	55,762,359	45,283,525	45,532,413	38,991,167	70,927	7,215,076	1,358,528
muni	45,272,136	40,574,901	41,361,471	19,840,719	95,754	1,528,685	610,802
Other	9,669,470	9,339,155	9,339,155	5,998,298	20,908	432,471	318,512
supplier	56,425,611	51,136,959	43,909,959	4,540,371	15,454	10,181,255	974,092
IOU	343,157,822	319,259,854	321,577,832	204,114,522	45,975	7,535,471	588,924
Total	**510,541,777**	**465,846,915**	**461,973,350**	**616,365,238**	**480,276**	**26,893,996**	**3,854,538**

Comparison of $ rates							
Awards	**Flows 100% of supply**	**Flows with grand-fathering**	**CRRs**	**CRR auction bids**	**Market bids**	**ISC Trades**	**Monthly SCID Fee**
$ 0.091368	**$ 0.287623**	**$ 0.292156**	**$ 0.011318**	**$ 1.00**	**$ 0.005**	**$ 1.00**	**$ 1,000**