California ISO
Shaping a Renewed Future

Responses to Stakeholder Comments on GMC 2012 Bill Comparison stakeholder meeting December 13, 2010

1. Charging system operations costs to supply		ISO comments
Coalition of Industrial cogeneration facilities	These comments are filed on behalf of a coalition of Industrial cogeneration facilities that provide thermal energy for industrial processes and generate electricity for sale to utilities pursuant to long-term contracts. The proposed grid management charge structure would impose a very significant increase in the grid management charge (GMC) for these generators, creating a severe financial constraint. This drastic increase seems due to two factors. First, the basic structure of the GMC has been changed so that generators are now charged for the energy they schedule and deliver to the grid. This fundamental change in the assessment of the GMC is unfair to suppliers that have existing contracts. Parties to existing contracts relied on the tariffs and regulations then existing to negotiate the financial responsibility for all expenses, including the GMC. The proposed GMC changes the assessment and the charge codes used for GMC, so any provisions of existing contracts related to GMC may become inapplicable. This financial risk imposed on long-term contracts is a particular disadvantage when compared with merchant plants, which make daily bids to sell their energy. Such merchant plants can adjust their bids to recover the additional costs of the new GMC. Suppliers with existing contracts may not be able to reach an accommodation with their buyers and would suffer a serious commercial disadvantage in competing with merchant plants. To resolve this penalty to existing contractual relationships, the new GMC structure should include a provision grandfathering transactions under existing contracts for some period of years. The GMC for such transactions would be assessed using the current methodology for the grandfathering period. At the expiration of the grandfathering period, the imposition of the new GMC would be phased in, perhaps transitioning from the existing methodology to the new one over three years. GMC billings may also significantly increase if the supplier had relatively low charges for schedule deviations under the current system. Some generators apparently historically accrued significant charges for deviations, and therefore, the imposition of new charges for delivered energy do not produce a significant net increase. But suppliers that did not have significant charges for deviations would now face an enormous net difference. These suppliers are in effect being penalized for their more accurate scheduling and operating behavior. In particular, industrial cogeneration, with its obligations to its steam host and its historically high capacity factor, should have minimal unscheduled deviations. The charges to individual suppliers for system operations should reflect the additional ISO activity required in real-time to balance deviations. Such activities by ISO staff are not related to the amount of MWh delivered, but the amount of deviation. ISO staff must perform far fewer scheduling actions to handle certain generators' compliant behavior than to compensate for another generator's deviations. The system operations charge should be disaggregated into two charges so that the costs of balancing the system can be properly allocated. Such a charge would not be a "penalty;" rather, it merely identifies and allocates the responsibility for the cost causation attributable to scheduling deviations.	Regarding RT deviations, the 2012 GMC proposal recognizes the fact that there really is no cost causation basis to assess additional GMC to such deviations under the new MRTU market design. This may not be well understood by all the market participants, but because of the new 5-minute economic dispatch using the full network model, which utilizes improved telemetry and a state estimator to provide accurate RT grid conditions, the impact of RT deviations on grid operators is nothing like what it was under the prior market system with zonal dispatch supplemented by operator-intensive out-of-sequence dispatch to mitigate local congestion. Indeed, an explicit objective of MRTU was to reduce the RT operational challenges of the old market system. With the new MRTU markets and systems it is no longer appropriate to assess additional GMC to RT deviations. Regarding the suggestion that existing contracts be grand-fathered, the ISO believes that the proposed 3-year phase-in period is a reasonable compromise to accommodate the transition to the new rate design.

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Calpine	General Comments The CAISO has proposed to substantially change both the cost allocation and the rate design for collection of its nearly $200 million operating cost. The current rate design for GMC includes 17 charge types which makes the transactional cost difficult to interpret. In addition, the existing rate structure creates incentives for market behavior that the CAISO apparently finds unattractive. The new proposal greatly simplifies the rate design by lobbing most costs into one of two “buckets” and creates a third category for congestion hedges. Calpine supports the CAISO’s effort to create simplifications and more transparency. However, the CAISO proposes to allocate GMC costs equally between supply and demand so one-half of the total costs of CAISO operations would be paid by supply. *(Note 1 - This is, by definition correct, but the CAISO has produced bill estimates that reflect the fact that a significant amount of supply is under the operational control of the state’s 3 largest IOUs).* For the reasons identified below, Calpine does not support incremental allocations of GMC costs to generation and imports. If the CAISO is not inclined to charge all GMC costs directly to load, where they will ultimately reside in any case, Calpine offers alternatives. Calpine does not support charging indirectly that which could be charged directly The CAISO proposes to “variablize” its fixed cost of operation and design rates to charge 98 percent of its costs to loads, exports, generation and imports. The billing determinants are generally Mwhs or MWs per hour *(Note 2 - The CAISO breaks out two buckets, one for “awards” and one for “flows”, but for simplicity, we lump them together)* for instance, for ancillary services. The average cost, when allocated this way will be roughly $0.40 per Mwh for every Mw of supply and every Mw of consumption. However, costs allocated to supply will not (for the most part) *(Note 3 - An unfortunate exception to this rule could be existing fixed-price contracts. We discuss them later)* remain with supply, as generation/import bids theoretically rise to cover the *expected value* of the actual GMC exposure. Thereby, the entire GMC cost will be allocated to loads – directly by the CAISO, and indirectly by generators and importers raising their supply bids. For a variety of reasons, suppliers will not know precisely what their GMC exposure will be. The simplicity of the new design does improve transparency and forecasting GMC exposure will be more accurate with this proposal than without it. Nonetheless, a supplier will not know *a priori* whether it will receive awards or what awards it will receive and what energy will flow and therefore, what GMC exposure it might have. In addition, since a single generator can provide multiple products, even if it could know with certainty the optimized IFM and RT outcomes, it is not feasible to differentiate each hourly bid of capacity by the specific allocation of expected GMC exposures.	Although it may be true that GMC cost will ultimately be passed to demand in some fashion, the objective of the GMC redesign is to align the ISO’s allocation of its costs on the basis of cost causation, i.e., the extent to which each market participant utilizes the services the ISO provides. During the stakeholder process the ISO did consider the alternative of full allocation of System Operations costs to demand, but has concluded that the proposed approach of allocating both to supply and demand reflects better alignment with the cost causation principle, while still supporting the other design principles. Regarding the assertion that suppliers will not know precisely what their GMC exposure will be for incorporation into their market bids, the ISO believes this concern is addressed by the fact that the charges are applied at a per-MWh rate. The supplier will either pay both the market and the grid GMC for a MWh of scheduled and delivered energy, or only the market GMC for a MW of awarded AS, or only the grid GMC for a MWh of uninstructed energy. It seems straightforward to add the

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	Rather than bidding the minimum-possible GMC, suppliers are more likely to bid the *expected value* – which could include a probabilistic view of the costs of awards, flows, ISTs, bid-segment fees and even possibly export fees. *(Note 4 - This expected value should also be in allowable in the Default Energy Bids which are used in LMPM*) This expected value would reflect the risk that GMC costs could be higher than the minimum possible exposure. So ultimately, loads could bear a risk-adjusted level of GMC costs that exceed the direct costs of CAISO operation. Charging the costs of GMC directly to loads and exports rather than indirectly to suppliers eliminates the payment of reasonable, but risk-adjusted supply bid costs. <u>The "Flow Through" theory is compelling, but not proven.</u> Parties have suggested that if all supply bids include the same GMC uplift, that dispatch order and infra-marginal revenue expectations for uncontracted assets should be unaffected. While some distortions will clearly occur, *(Note 5 – For instance, the average cost of non-spin for the month of November was less than the proposed GMC charges. The cost of non-spin would more than double with this change).* Calpine believes that if these assumptions are proven out, that generator and import revenue expectations would be unchanged. However, Calpine is predominantly an infra-marginal supplier. It does not control the resources that are generally on the margin and those who might control marginal resources will have a different *expected value* of risk and cost exposures that may influence their bid levels. Revenue compression for infra-marginal generation is a certain possibility if marginal generators (or those bidding marginal generation) face lower risk expectations. <u>Calpine agrees that the CAISO should "Seek To Do No Harm."</u> In the November Straw Proposal, the CAISO describes its "Guiding Policy and Ratemaking Principles" at page 4. In the discussion of the second principle, the CAISO confirms that "a properly designed GMC should seek to do no harm," and that it "is simply a mechanism to recover ISO revenue requirements in a manner which minimizes market impacts". Calpine strongly endorses the concept that GMC should avoid market impacts and believes that allocations of GMC to generation and imports could and will affect market outcomes. In addition to mitigating effects on existing contracts, we offer several alternatives that could minimize the exposure to unnecessary costs or unintended consequences. <u>Calpine supports accommodations for pre-existing contracts</u> The "pass-through" theory clearly fails if the added costs of an increased GMC cost cannot be passed through to contractual counterparties. In this case, an allocation of the GMC cost to suppliers simply	estimated market GMC charge to AS bids and both the market and grid GMC charges to energy bids, to reflect the differential GMC costs of providing those products. Indeed, the GMC redesign process adopted the principles of transparency and predictability precisely to enable market participants to account easily for these charges in their bidding strategies and other business decisions. Therefore it is hard to see why there would need to be a risk premium on supplier energy or capacity bids to reflect GMC uncertainty. Regarding Default Energy Bids, it may be appropriate to consider including GMC costs, but this matter is outside the scope of this 2012 GMC redesign and should be pursued through the Market Initiatives Roadmap process that will occur later this year. Regarding the marginal/infra-marginal issue, the argument seems to be that marginal resources may include a smaller GMC risk premium on their bids than infra-marginal resources do, thus squeezing revenues for the infra-marginal. But this could just as well go the other way. If marginal resources use a larger

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	increases their costs and provides a windfall to loads, as loads avoid costs of operating the CAISO. In particular, fixed-price, long-term contracts which split the SC responsibility between supply and load will not generally allow pass-through *(Note 6 - Of course, provisions of the underlying contract may allow pass-through)*. Calpine has long-term, fixed-price contracts *(Note 7 - Calpine is certainly willing to share these contracts confidentially with the CAISO, as long as such is allowed under the contract)* for base load energy where the cost of GMC (if allocated to supply as proposed) would increase by a fact of 10 from an aggregate GMC exposure of about $250,000 to over $2.5 million. Such a dramatic change in the allocation of GMC would not have been anticipated by reasonable negotiators when such a deal was struck. In addition, such a dramatic effect on market outcomes was probably not anticipated by those designing the new GMC structure. However, a theory of "do no harm" would require that such contracts be accommodated for the remaining tenure of the contract. Calpine is open to reasonable mitigation measures that continue to assess long-term, fixed-price contracts an allocation of GMC as long as it is consistent with historical, and not proposed rates. For instance, Calpine would accept a fixed-cost GMC annual payment (e.g. historical allocations reasonably escalated) or a substantially pro-rated volumetric charge (e.g. one-tenth of the per-mwh charge.) <u>Calpine proposes alternatives if the CAISO imposes GMC charges on supply</u> As a first principle, Calpine proposes that *if* the CAISO determines that it must charge supply, that imports and internal generation face precisely the same cost exposure. Differentiated pricing creates the unintended consequence of artificially favoring imports or internal generation. Calpine understands that the CAISO seeks to apply this same symmetry principle to all resources because "both load and generation will provide similar services". *(Note 8 - Straw Proposal* p7) Certain new technologies might need to be treated differently (e.g. DSM reductions should compete price-wise with incremental generation) but as discussed below, Calpine asserts that load is the major beneficiary of CAISO operational systems and should therefore bear most of the costs. Each of the options below decrease the risk that the CAISO could impose unrecoverable costs on supply or otherwise create harm or unintended market impacts. <u>Option 1 – Charge Supply only the Market Services Charge.</u> If the CAISO does impose costs on supply, Calpine supports the comments of SCE *(Note 9 - SCE's comments on the Discussion Paper, submitted October 21)* which suggest that generation pay the Market Services charges and not the System Operations charges. As SCE suggests "the benefits of reliable System Operations are accruing to demand." Indeed, the CAISO indicates that the "fundamental purpose of system operations is to balance supply and demand." Additionally, SCE is concerned with price distortions that	risk premium, then the infra-marginal resources would realize expanded revenues. Regarding the fixed-price contract issue, the ISO believes that the proposed 3-year phase-in should adequately address this concern. Regarding comparable charges to internal generators and import suppliers, the GMC proposal does this. Regarding the assertion that "load is the major beneficiary of CAISO operational systems," the ISO believes that although it may be argued that the raison d'être of the electricity sector is to provide electricity to end-use consumers, the ISO's provision of open, non-discriminatory transmission service and transparent spot markets provides benefits to all industry participants. Regarding the idea of a "conditional" transition to full application of charges to supply, the ISO points to the example of the energy bid cap transition under the MRTU design, where FERC approved a series of steps up to the $1000/MWh level, but did not make these steps

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	arise as GMC bid adders are included in IFM results. Option 2 – Charge Supply, but on a pro-rated basis As with pre-existing contracts, supply could be charged a pro-rated charge (as a percent of Mwh or price) for both Market Services and System Operations that reflects the possibility that the "pass through" theory may fail. Option 3 – Charge Supply, with a conditional transition As an alternative to option 2, the CAISO could prescribe a transition plan in which supply's pro-rated share of the GMC would increase over, say 4-5 years. This transition period would allow bilateral contracts to expire and be reformed with a clear expectation of future risk. The annual escalation of the discount percentage could be made contingent upon a finding by an independent party that the "pass through" theory is supported.	conditional on other events or findings. This approach provides the market much better certainty – also a principle of the GMC design – than conditioning a subsequent phase-in step on some kind of finding. The ISO believes therefore that the same design is most likely to receive FERC approval for the GMC phase-in, i.e., a fixed timetable for the steps of the phase-in.

2. CRRs		ISO comments
PG&E	<u>General Comments</u> Overall, PG&E supports the CAISO's 2012 GMC rate design proposal. Under the CAISO's proposed rate design, market participants will be assessed GMC based on how much they use CAISO-run markets and the CAISO-controlled transmission system. This will provide greater transparency than exists under the current GMC rate design and will allow market participants to more easily determine the "GMC impact" of any Market Services or System Operations transaction. With respect to the CAISO's proposed GMC to recover the costs of managing the Congestion Revenue Rights (CRRs) market, as discussed further below, PG&E believes that the CRR charge is adequate for the time being, but future improvements are necessary. <u>Improvements in the GMC CRR Charge</u> PG&E supports the CAISO proposal for a CRR GMC based on both awarded MWHs and a Bid Transaction Fee. PG&E's support is tempered by the current lack of detailed cost data associated with CRRs. PG&E believes that a MWH-based charge does not accurately apply GMC to the market participants which cause costs to be incurred. However, lacking detailed cost studies, a MWH-based GMC charge meets several of the guiding policy principles for the new GMC structure, *i.e.,* predictability, transparency, flexibility and simplicity. However, in PG&E's opinion the most important principle is cost causation and a GMC charge based on CRR MWH does not meet this criterion. PG&E reiterates its prior comments that costs associated with CRR services are independent of the MWH awarded. CRR costs are a function of the number of allocation/auction nominations, the number of awarded CRRs, the number of CRRs transferred through the load migration process and the number of CRRs transferred through the secondary registration market. Of these cost drivers, only the cost associated with the nominations are addressed through a CRR Bid Transaction Fee, currently proposed to be $1 per nomination. To appropriately assess fees associated with the aforementioned cost drivers, a detailed cost study is needed. Currently, the CAISO proposes to recover the costs of running its CRR market primarily through a MWH-based charge (proposed to be $0.01179/MWH). PG&E agrees that this is a reasonable and expedient initial rate structure. It is PG&E's recommendation that CRR cost studies be performed in the future so that improvements can be made to the CRR charge rate structure and the $/MWH billing determinant can be replaced by a transaction-based structure. <u>PG&E Supports the CRR Bid Transaction Fee</u> PG&E would like to see the CRR Bid Transaction Fee defined as precisely as possible. In various presentations and published documents, CAISO has defined the CRR Bid Transaction Fee differently. PG&E supports a fee assessed to each nomination bid in the annual, long-term and monthly allocations and the annual and monthly auctions. In the case of an allocation tier, a nomination bid is a submission by a market participant which	Regarding the concern about potential inequity between holders of allocated CRRs versus holders of auctioned CRRs, the ISO points out that the benefits all parties receive from the CRR element of the market structure are directly proportional to the total MW amounts of their holdings. It is therefore appropriate to recover the costs of the CRR processes and systems on this basis, irrespective of whether the CRRs were awarded through allocation or auction. Regarding using MWh as the billing determinant: All guiding principles have similar weight overall in the recovery of ISO costs; however, their relative importance can change through the process. For example, cost causation is most important in the allocation of costs to each of the GMC cost category. Activity based costing is a pure form of cost causation and was utilized as part of the cost of service study is determining the total costs that must recovered by each GMC cost category. However, when establishing the billing determinant other guiding principles such as predictability and forecastability increase in relative importance.

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	specifies a source Pnode, a sink Pnode, the MW amount and the time-of-use period. For an auction, a nomination bid includes the data submitted in the allocation nomination in addition to the bid curve which specifies MW quantities and $/MW bids. Another suitable definition for a nomination bid is a submission which generates a Nomination ID in the CAISO CRR MUI. At the recent December 13, 2010 GMC Stakeholder Meeting, a market participant stated that a bid transaction fee does not reflect cost causation. PG&E disagrees. The CAISO's CRR systems were designed to handle a finite amount of allocation and auction bids. There are limits to how many nominations can be uploaded via the CRR MUI. A bid transaction fee better reflects cost causation than a $/MWH GMC. While there can be some debate as to whether $1 is the right amount to charge per nomination, the transaction-based structure is valid and appropriately reflects cost causation. PG&E notes that the proposed CRR Bid Transaction Fee recovers approximately $480 thousand, roughly 6.5% of the total CRR market cost of $7.5 Million. PG&E believes that this is an acceptable amount and PG&E would support an even higher percent recovery from a CRR Bid Transaction Fee. Going forward, PG&E would support expanding the CRR Bid Transaction Fee so as to reflect the term of the CRR being nominated. CRRs have three terms or durations: monthly durations (from the monthly processes), quarterly durations (from the annual process) and nine quarters (from the long-term allocation). Furthermore, PG&E believes that higher bid transaction fees would be appropriate for the annual and long-term process, compared to the monthly process. <u>GMC Inequity Between Auction and Allocation Participants</u> PG&E is concerned that the application of the CRR $/MWH charge and Bid Transaction Fee affects CRR allocation participants more than auction participants. Auction participants can adjust their bids to effectively recover all, or a portion of, the cost of the $/MWH charge and Bid Transaction Fee. That is, PG&E expects CRR auction clearing prices to reflect the new CRR GMC charge and fee. This will permit auction participants to pass such GMC costs through to the market, or else factor such GMC costs into their bids. CRR allocation participants do not have a similar mechanism at their disposal. PG&E would like CAISO to investigate this issue and consider alternative fee structures to address any inequities. <u>Question Regarding the Timing CRR Bid Transaction Fee</u> CAISO has not provided specifics regarding when the CRR Bid Transaction Fee will be assessed. The simplest method to assess the fees would be at the time the nominations are submitted. This means that the fee would be assessed from one month to nine years before the term of the CRR. PG&E asks CAISO to provide more details about the timing of the CRR Bid Transaction Fee.	One of the issues with the current GMC design that limits the ability for market participants in assessing their GMC exposure is applying solely cost causation to the establishment of billing determinants such as forward scheduling and imbalance energy. The selection of these billing determinants may have merit from a cost causation standpoint but do not reflect the relative benefit a market participant receives from the ISO service and is extremely difficult to forecast thus decreasing the predictability of the actual GMC rate. Regarding the CRR Nomination and Bid Fee: The Nomination fee applies per tier for each source sink pair and time of use. The Bid fee applies for each auction submission of source sink pair and time of use. Since the rate structure would not become effective until 2012 and the annual allocation / auction process occurs in late 2011 for 2012 CRRs, it does seem that for the annual 2012 process the $1.00 bid fee would not be in effect. In addition, the January 2012 monthly

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	<u>Questions Regarding the CRR Data Used in the 2012 GMC Customer Bill Impacts</u> The 2012 GMC Customer Bill Impact analyses used invoiced billing determinant quantities for the period June 2009 to May 2010. PG&E noticed that all the bids were characterized as "Auction Bids." Is this correct or do the quantities include Annual and Monthly Allocation Tier Nominations? In addition, did the bid count include nominations from two annual processes, *i.e.*, 2009 and 2010? Finally, it appears that no long-term allocation nominations were included. Can CAISO confirm if this is correct?	submission of bid/nominations would occur in 2011. Also, the February 2012 monthly process would have already begun but most likely nomination/bid submission would occur in 2012. So the bid/nomination fee will not impact all 2012 CRRs equally. The MWh portion would become effective for CRRs which are held in 2012, even though they cleared the market in 2011, because the corresponding settlements will occur after 1/1/2012. The CRR data only included transactions that would have gone through settlements for the period June 2009 to May 2010. The data is labeled as to which auction it refers.
Edison Mission	Please confirm that 2012 GMC will apply to grid activity effective Jan 1, 2012. For example: • 2012 GMC rates will not apply to CRR awarded positions prior to Jan 2012. • 2012 GMC rates are effective Jan 1, 20102 for awarded market position that settle on flow date Jan 1, 2012 and after	That is true - see comments to PG&E above
DC Energy	DC Energy submits these brief comments on the CAISO proposal to add a new charge to CRR holders associated with the 2012 Grid Management Charge (GMC) process. DC Energy believes that CRR market participants should bear an appropriate share of the GMC costs as CRR market participants share in the benefits of the CAISO markets. DC Energy agrees with the statements of SCE and CAISO in the November 2010 Straw Proposal: "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	The ISO believes that we have met our guidelines for this rate design and endeavor to provide lead time to participants to make changes in their business practices to incorporate these future GMC revisions.

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	do no harm (negatively affecting market outcomes) avoid imposing negative incentives (address negative market behavior such as deviations), and is simply a mechanism to recover ISO revenue requirements in a manner which minimizes market impacts.” DC Energy appreciates CAISO’s recognition of an appropriate transition period and introducing, for the first time, a CRR bid and award charge beginning in 2012. DC Energy also believes CAISO has met its stated goal of adhering to certain Guiding Principles *(note 1 - Cost causation, focus on use of services, transparency, predictability, forecastability, flexibility and simplicity),* as presented at the December 13th Stakeholder meeting.	

3. SCID charges and TORs		ISO comments
MID	The Modesto Irrigation District ("MID") thanks the California Independent System Operator Corporation ("CAISO" or "ISO") for the opportunity to comment on topics discussed at the December 13, 2010 stakeholder meeting on 2012 Grid Management Charge ("GMC") projected billing impacts. At the December 13 meeting, the CAISO discussed that it had two proposals it wished to make with respect to the 2102 GMC. The first proposal is to continue the CAISO's current treatment of SCIDs in the GMC charging $1000/month for its SCID fee only if there is any activity on the Scheduling Coordinators ("SC") invoice. While MID has not favored per-SCID charges, MID appreciates the CAISO's suggestion and believes it is a reasonable compromise. The second proposal is to exclude transmission ownership rights ("TORs") entirely from the market services charge. In addition, the CAISO proposes to exclude TORs from the System Operations charge 50% of the higher of supply or demand. If that is an accurate description of what the CAISO intends, then MID supports the proposal. MID went into detail in its November 24, 2010 comments as to why the GMC rate design should reflect the lower, relative costs of TORs. MID believes that the CAIS's December 13 proposal on TORs better reflects cost causation, and accordingly, MID supports it. However, MID understands that the CAISO intends to put in writing its proposal concerning TORs, and MID reserves the right to supplement or modify its position, if the CAISO's written proposal is different than what MID has noted above, or the proposal is subsequently modified or MID learns new information in the forthcoming stakeholder discussions.	Regarding SCID fees and TORs the proposals will be described in the paper to be issued January 13, 2011.

4. Cost shifts and customer category data		ISO comments
WPTF	WPTF offers some high-level comments and defers to its members' comments on more specific impacts or issues. WPTF supports the publishing of more sector-specific impact summaries, consistent with the requests of other parties made during the 12/13/10 meeting. WPTF is concerned that the CAISO's most recent GMC proposal would allocate the GMC – a charge historically collected from loads and exports – to new parties, creating significant cost shifts for some and potentially affecting market efficiency. WPTF requests that the CAISO comment on the merits of the cost shifts and address whether further consideration is required – for example on the CRR bid fee – to ensure market efficiency is not hampered.	The ISO published additional customer category to the GMC website on December 16, 2010 and will do the same for the modified proposal to be issued January 13, 2011. See responses to comments of Calpine, the coalition of industrial cogeneration facilities and PG&E above.