UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	))))	Docket No. ER04-____-000

GRID MANAGEMENT CHARGE

VOLUME IX OF IX

- Exhibit Numbers ISO-335 through ISO-383

October 31, 2003

APPENDIX 4, ATTACHMENT A: Functionalization of Activity Groupings for ISO Rate Structure (SUBJECT TO CHANGE)

Function	Sub-Function	Direct Personnel	Activities within proposed Grouping	Indicative Cost Centers (There is some overlap among cost centers)	Applications
Grid Reliability Services	Core Reliability Services (base level) Energy and Transmission Services (scalable portion)	Real-Time Grid Operations • RT Grid Resource Coordination • Gen Dispatchers • RT Intertie Scheduling • Trans Dispatchers	Ancillary Services management: • Dispatch of energy associated with Ancillary Services, including: o Regulation o Spin o Non-spin o Replacement reserve o Black start Monitoring of system conditions and dispatching to maintain reliability: • Load and resource balancing • Transmission line/path congestion management • Voltage control • Frequency control • System emergency management • Power flow studies and security analyses Determination of resource adequacy in real time Coordinating Western Interconnection reliability with all WECC Reliability Coordinators Integration and communication with other Control Areas: • Interconnected switching operations for planned and unplanned outages • Generation and transmission equipment outage coordination Interchange scheduling ETC scheduling and administration EMS and Telemetry management	1544 – Real Time Scheduling 1564 – Operations Scheduling 1546 – Security Coordination 1545 – Grid Operations 1566 – Regional Coordination 1461 – Control Systems 1752 – Manager of Markets (portion) 1462 – Field Data Acquisition (portion)	See Cost Allocation Matrix detail on assignment of system applications

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Grid Reliability Services	Core Reliability Services (base level) Energy and Transmission Services (scalable portion)	Interchange Pre-Scheduling WECC Requirements	Day-ahead/Hour-ahead intertie scheduling • ETAG (NERC-required electronic schedule tagging) • Existing Transmission Contracts Calculator (ETCC) and scheduling • New Firm Uses (NFU) scheduling Reconciliation of schedules and interchange after-the-fact NERC/WECC/CAISO Tariff required reporting Weekly: • Inadvertent Interchange report • NERC reports (Inadvertent Interchange, ETAG) • WECC "donut" report Monthly: • WECC Unscheduled Flow curtailment report Quarterly: • Quarterly California Energy Commission 1305 report Annually: • SDG&E DOE report • FERC 714 report • Report of Economic Operation	1565 – Pre-scheduling and Support	
Grid Reliability Services	Core Reliability Services (base level) Energy and Transmission Services (scalable portion)	Outage Coordination	Pre-planning of and preparation for generation and transmission outages Generation and transmission equipment outage tracking and data/record keeping On-site generation outage monitoring (SB-39 compliance) Outage reporting (web site updates and regulatory agency reporting) Supply of Generation and Transmission data for OASIS postings	1542 Outage Coordination	

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Grid Reliability Services	Core Reliability Services (base level) Energy and Transmission Services (scalable portion)	Operations Engineering, Maintenance, and Support	Transmission Maintenance: • Develop, monitor and enforce of transmission maintenance standards • Manage and oversee new generation interconnections, major capacity additions or upgrades and supporting Transmission Planning in project tracking. • Manage, analyze, prepare reports on system availability, reliability, and outage records. • Manage, audit, investigate, approving Transmission Maintenance Practices. • Manage, oversee, and approve the equipment ratings. Operations Engineering: • Perform seasonal, annual, and, as necessary special analysis of transmission system performance and ratings. • Review, approve and provide specification on daily system configurations, emergency conditions, clearances and operational conditions. • Develop, prepare and update operating procedures. • Perform operational studies and system security analyses Operations Support: Manage the development, preparation and revision of all ISO Operating Procedures: • Transmission grid • Market Operations • Generation • Emergency • Perform generating unit ancillary service certification and P-MAX testing • Manage UDC and Inter-Control Area Operating agreements • Manage dynamic energy scheduling agreements and interfaces • Manage required WECC Reliability Management System (RMS) and NERC • Maintain Compliance Program data collection, tracking, storage and reporting processes	1558 – Transmission Maintenance 1561 – Operations Engineering, South 1562 – Operations Engineering, North 1554 – Special Projects Engineering 1549 – Operations Training Group 1555 – Operations Support Group 1559 – Operations Application Support 1563 – Coordinated Operations	

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Grid Reliability Services	Core Reliability Services (base level) Energy and Transmission Services (scalable portion)	Loads & Resources Grid Planning Operations R&D	Transmission Planning: • Perform system transmission planning to ensure overall reliability • Perform reserve requirement studies • Perform Long-term (monthly, annual and longer) load forecasting • Determine long term *transmission* resource adequacy Regional Coordination: • Coordinate participation in NERC, WECC, NAESB, ESC, and OSC • Monitor and participate in resolving seams issues in the Western Interconnection • Provide Control Area and interconnection mapping services to real time operations. Determine long-term *generation* resource adequacy: • Manage, develop, prepare, publish and participate in seasonal system load and generation assessments. • Participate, guide, influence, and maintain records on environmentally constrained generation units. • Determine dual fuel generator requirements Determine Reliability Must-Run ("RMR") contract requirements Review Participating Transmission Owners ("PTOs") Bulk Power Program and new generator or load interconnection studies	1521 – Grid Planning 1543 – Loads and Resources 1566 – Regional Coordination	
Grid Reliability Services	Core Reliability Services (base level)	Reliability Contract Administration	Administration of RMR settlements Validation of Summer Reliability Generation invoices Development and implementation of Tariff modifications Maintenance of agreements with existing and new clients Meeting regulatory directives related to contract activities Non-vendor contract administration	1723 Tariff and Contracts Implementation 1731 Contracts and Special Projects (portion)	

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Function	Sub-Function	Direct Personnel	Activities within proposed Grouping	Indicative Cost Centers (There is some overlap among cost centers)	Applications
Grid Reliability Services	Energy and Transmission Services (scalable portion)	Market Monitoring and Compliance	Evaluation of transmission capacity expansion Review and recommend changes to ISO rules and protocols Monitor and measure operational performance consistent with contractual commitments and Tariff requirements Ensure generator compliance with dispatch instructions and must offer requirements Administer ISO Oversight and Investigations Review	1641 – Market Analysis (portion) 1642 – Market Surveillance Committee (portion) 1661 – Compliance (portion) 1662 – Data Quality Group (portion)	
Market Services	Forward Scheduling	HA Grid Resources Coordination DA Grid Resources Coordination Markets & Scheduling Group (portion) Market Operations (portion) Market Engineering (portion) Business Solutions (portion) Market Integration (portion) Congestion (portion) ETCs	Manage transmission and generation schedules: • Day and Hour-Ahead schedules (including Participating Intermittent Resources) • Determine schedule feasibility	1752 – Manager of Markets (portion) 1753 – Market Application and Testing 1755 – Business Solutions (portion) 1757 – Market Integration (portion)	
Market Services	Congestion Management	Congestion (portion)	Manage inter-zonal congestion	1752 – Manager of Markets (portion) 1753 – Market Application and Testing 1755 – Business Solutions (portion) 1757 – Market Integration 1756 – Market Quality (portion)	

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Function	Sub-Function	Direct Personnel	Activities within proposed Grouping	Indicative Cost Centers (There is some overlap among cost centers)	Applications
Market Services	Congestion Management	Marketing monitoring	Monitoring and reporting on congestion management market performance Investigating and reporting on potential gaming and market power abuses (congestion)	1641 – Market Analysis (portion) 1642 – Market Surveillance Committee (portion) 1661 – Compliance (portion) 1662 – Data Quality Group (portion)	
Market Services	Market Usage	Market Operations Manager of Markets Market Quality (portion) Market Eng (portion) Business Solution (portion) Market Integration (portion) Markets & Scheduling Group (portion) Market Monitoring & Compliance FTR Auctions	Perform weekly, daily and hourly load forecasting Operate A/S and Real-Time markets Determine market clearing prices (A/S and Energy) Mitigate bids (real time and forward) Maintenance of market information postings (transmission/market OASIS) Operate unit commitment service under SMD Mitigate market power in Day-Ahead, Hour-Ahead and Real Time markets Develop and manage demand response participation Administer FTRs: • Perform FTR auctions (Primary) • Coordinate FTR bilateral trading (Secondary) • Calculate and determine feasibility of FTR capacity	1752 – Manager of Markets 1753 – Market Application and Testing 1757 – Market Integration 1756 – Market Quality (portion)	
Market Services	Market Usage	Marketing monitoring and compliance	Monitor and report on market performance Investigate and report on potential gaming and market abuses Perform special studies on market efficiency, bidding behavior Develop new market rules or changes to market rules in response to market behavior Prepare and provide reports to regulatory authorities Implement and calculate penalties and sanctions for noncompliance	1641 – Market Analysis (portion) 1642 – Market Surveillance Committee (portion) 1661 – Compliance (portion) 1662 – Data Quality Group (portion)	

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Function	Sub-Function	Direct Personnel	Activities within proposed Grouping	Indicative Cost Centers (There is some overlap among cost centers)	Applications
Settlements, Metering and Client Relations		Settlements, Billing, Credit Administration and Metering	Determine charges associated with: • Transmission services • Day-Ahead schedules and markets (A/S and Energy) • Hour-Ahead schedules and markets (A/S and Energy) • Real time balancing energy market • Congestion management • Administrative charges, including the Grid Management Charge Manage settlement data Manage ETC manual settlements Prepare market and GMC invoices Prepare special invoices for FERC fees, interest, etc. Perform settlement statement reruns Market/settlements design and settlements training Dispute resolution, GFN, arbitration and monitoring Credit and collateral management • Manage collections and payments • SC financial security analysis Determination of losses and allocation Metering and data management • Collect and validate data from ISO polled meters • Repository of data polled from ISO polled meters and data submitted by SCs • Responsible for site inspection of metering sites • Responsible for setting up RIG data bases and submitting data into EMS • Push data to Settlement databases Manage Participating Intermittent Resources settlements	1722 – Application Support 1723 – Tariff and contract implementation 1724 – BBS-PSS 1725 – BBS-FSS 1462 – Field Data Acquisition (portion) 1321 - Accounting 1756 – Market Quality (portion)	

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Function	Sub-Function	Direct Personnel	Activities within proposed Grouping	Indicative Cost Centers (There is some overlap among cost centers)	Applications
Settlements, Metering and Client Relations		Account Management Services and Training	Provide ISO Tariff, Systems, Market and Settlements guidance to market participants Communicate scheduled events to market participants Communicate Market information Develop training curriculum Provide training to Market Participants (Settlements, System Infrastructure, Market Design) Facilitate stakeholder process Facilitate resolution of Market Participant issues	1741 – Client Relations	
Settlements, Metering and Client Relations		ISO contract administration	Administer ISO contracts (non-vendor, e.g., RMR, PTO, MSS) Negotiate, manage, litigate contracts	1731 – Contracts and Special Projects (portion)	
		Administrative and General (not directly assigned elsewhere	CEO Finance and Accounting Legal HR Regulatory policy and affairs Information services Strategic development Communications	1111 – CEO 1651 – Board of Governors 1241 – MD02 (currently) 1300 – Finance indirects 1400 – Information Services indirects 1600 – Legal and Regulatory indirects 1700 – Market Services indirects 1800 – Corporate and Strategic Development indirects	
All	All	Startup costs	Recover costs associated with Startup		

APPENDIX 4, ATTACHMENT B

Comparison of California ISO Rate Structure Proposal to Rate Structures of other ISO/RTOs

	Reliability Function		
ISO/RTO	Name	Description	Billing Determinant
ISO-NE	Reliability Administration (Schedule 3)	Administer reliability markets, including Operating Reserve Markets, AGC/Regulation markets, ICAP settlement. Examples of functions performed: gen. dispatch associated with reliability markets; reliability markets accounting; billing preparation; generation emissions analysis; risk profile updates; resource adequacy reviews; regional reports/load forecasts/profiles (CELT, EIA, NERC); support of power supply, environmental, market reliability planning activities; market power monitoring, mitigation and assessment of reliability markets; formulation of additional reliability market rules.	Non-coincident kW-months
NYISO	NA bundled rate		
PJM	Control Area (schedule 9-1)	Control Area Services includes costs of all PJM activities associated with preserving the reliability of the PJM and PJM West control areas and administering point to point transmission service and network integration transmission service.	MWhs of point to point and network integration services flows
	Regulation and Frequency Response (Schedule 9-5)	Regulation and Frequency Response Administration Service includes the costs associated with administering the provision of Regulation and Frequency Response Service under Schedule 3 of the Tariff. PJM provides this service to Load Serving Entities and to generators that provide regulation in accordance with Schedule 3.	MWhs of PJM regulation plus scheduled (including self-scheduled) regulation
	Capacity and Resource Obligation Management (Schedule 9-7)	Capacity Resource and Obligation Management Service includes the costs associated with (i) assuring that customers have arranged for sufficient generating capacity to meet their installed capacity obligations under the RAA and RAA-West; (ii) processing Network Integration Transmission Service; and (iii) administering the capacity credit market in the PJM Control Area and available capacity credit market in the PJM West Region	Allocated to East/West by relative East/West non-coincident peak assessed on MW-days
ERCOT	Bundled rate		
Ontario IMO	Bundled rate		
Midwest ISO	No separate Reliability Function		
CAISO (Proposed)	Core Reliability Services	In this sub-function, the ISO provides a stable grid and meets regional and national regulatory requirements, such as NERC and WECC reliability criteria and some FERC requirements (e.g., a basic level of transmission planning). All necessary activities attributable to Control Area operation including the capability of handling a system that is as geographically dispersed as the present system but without features that are scalable (i.e., that vary according to use or size of flow) are contained in this function.	Non-coincident peak demand including behind the meter non-coincident peak demand QF NCP adjusted for diversity(MW)
	Energy and Transmission Services	The ISO provides more than the basic level of the safe, reliable operation of a Control Area surrounded by other control areas assuming everyday (normal and extraordinary) operational requirements in which outages and other disruptions occur frequently and consistently. This is the scalable portion of Reliability Services that occurs due to the everyday occurrence of system activity.	Net control area load (MWh)

	Market Services Function		
ISO/RTO	Name	Description	Billing Determinant
ISO-NE	Scheduling, System Control and Dispatch (Schedule 1)	Includes scheduling service, provision of A/S. Processing requests for transmission service, coordination of transmission system operation, billing associated with transmission service, transmission system planning, administrative support for these.	Monthly Network load in kW plus highest amount of reserved capacity of point to point transmission service plus the highest amount of unauthorized use
	Energy Administration (Schedule 2)	Includes dispatch service. Administer energy market and facilitate interchange transactions, bilateral transactions and generator bids. In summary: Generator dispatch, energy accounting, loss determination and allocation, billing preparation, administration of imbalance energy service, market power monitoring & mitigation, sanction activities, energy market assessments & reports, formulation of market rules, administer FTRs, ARRs.	15% to Transaction units – bilateral contract block hours plus generator block hours plus "net deviation" block hours 85 % to Load and injections MWh
NYISO	NA bundled rate		
PJM	Market Support (Schedule 9-4)	Market Support Service includes costs associated with supporting the operation of the PJM Interchange Energy Market and related functions, as described in Schedule 1 of the Operating Agreement and the Appendix to Attachment K to the Tariff, including, market modeling and scheduling functions, locational marginal pricing support, market settlements and billing, and market monitoring.	Generation and Load MWh
	Fixed Transmission Rights (Schedule 9-3)	Fixed Transmission Rights Administration Service includes the costs associated with administering the Fixed Transmission Rights ("FTRs") provided for under Attachment K to this Tariff, including, coordination of FTR bilateral trading, administration of FTR auctions, support of PJM's on-line, Internet-based eFTR tool, and analyses to determine what total combination of FTRs can be outstanding and accommodated by the PJM system at a given time	FTR MW per hour summed over hours
ERCOT			
Ontario IMO			
Midwest ISO			

CAISO (Proposed)	Market Scheduling	The ISO provides energy and Ancillary Services scheduling in forward markets and processing of accepted Ancillary Services bids. In this context, a schedule is represented by a scheduling template (import, export, load, generation, inter-SC trade and Ancillary Services, including self-provided AS) submitted to the ISO Scheduling Infrastructure.	Per schedule, import, export, load, generation, interSC trade and AS, submitted
	Congestion Management	The ISO provides management and operation of inter-zonal congestion markets, using adjustment bids, taking Firm Transmission Rights and Existing Transmission Contracts into account, and determining the price for mitigating congestion for flows on congested paths.	MWhs of Scheduled Interzonal flows (load)
	Market Usage	The ISO provides access to forward and Real-Time energy and Ancillary Services markets.	MWhs purchases and sales of Ancillary Services, instructed energy and the absolute value of net uninstructed deviations. No assessment on self-provided Ancillary Services

Annual Fee			
	Name	Description	Billing Determinant
ISO-NE	Annual fee, no separate CS function	$5,000/year	
NYISO	Annual fee, no separate CS function	Small Consumers $100 – 0 to 499 MWh/year $500 – 500 to 1999 MWh/year $1,000 – greater than 2000 MWh/year $5,000 – all other companies	
PJM	Annual fee, no separate CS function	$5,000/year	
ERCOT	Annual fee, no separate CS function	$2,000 – full members $500 – adjunct members	
Ontario IMO	Annual fee, no separate CS function	$0 – 0 to 99 MWh/year $1,000 – 100 to 2,999 MWh/year $8,000 – greater than 3,000 MWh/year <	
MidWest ISO	Annual fee, no separate CS function	none	
CAISO (Proposed)	Settlements, Metering and Client Relations	Monthly fee of $500 per SC ID	

Startup Costs			
	Name	Description	Billing Determinant
ISO-NE	No separate startup cost component		
NYISO	Separate collection of Start-up costs	Separate collection and amortization of start-up costs. Currently the annual amortization is $13.15 million. The rate for March is approximately $0.47 per MWh.	MWh
PJM	No separate startup cost component		
ERCOT	No separate startup cost component		
Midwest ISO			
CAISO (Proposed)	Start-up Costs	Recovery of bond financed capital expenditures from 1997 through 2000. The annual debt service cost is approximately $43 million with an additional $11 million collected in interest coverage. The bonds are fully amortized in 2009.	Assigned to other rate components

CHRISTENSEN ASSOCIATES

A Rate Design Proposal for the Grid Management Charge of the California Independent System Operator

By
Laurence D. Kirsch, Ph.D.
July 10, 2003

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A Rate Design Proposal for the Grid Management Charge of the California Independent System Operator

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Submitted on Behalf of
Modesto Irrigation District

July 10, 2003

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TO: Board of Governors, California Independent System Operator

FROM: Dr. Laurence D. Kirsch and Dr. Ross C. Hemphill

DATE: July 10, 2003

SUBJECT: Rate Design Proposal for the Grid Management Charge

On behalf of Modesto Irrigation District, we provide to you this package of documents that describes and supports the rate design that we propose for the California ISO's Grid Management Charge (GMC). This memorandum summarizes our proposal. The accompanying *technical paper*, entitled "Rate Design of the California ISO's Grid Management Charge," describes the proposal in detail. The technical paper is followed by our *resumes*. The final section of this package contains *supporting documents* that presents two published power engineering articles and a recent ISO Staff memorandum, all three of which affirm our view of the services provided by system operators.

Our rate design proposal is superior to the existing rate and to the other proposals you will see because: 1) it fully satisfies the intent of the FERC directive and the objectives established by the ISO's stakeholder review process; 2) it will not have to be changed to accommodate locational pricing (LMP) or any other element of MD02; and 3) it raises fewer issues subject to litigation from other stakeholders. Our proposal is based upon long-held public utility ratemaking principles that functionalize, classify, and allocate costs based on the services provided to and used by market participants. Our rate design is the only proposal that is clearly focused on recovering revenues from customers for services rendered commensurate with the costs incurred. And again, unlike the ISO Staff proposal, this proposal will not require a new rate design when the ISO switches from zonal pricing to LMP. We believe that the inherent stability of this proposal is more consistent with direction most stakeholders wish to see in the design of a GMC.

Fundamental Principles

The foundation of our proposal is that pricing should reflect the cost of services rendered. The GMC should be designed so that, to the extent practicable, customers pay for the services that customers use. The principle that customers should pay for the services they use is basic to virtually all markets, both competitive and regulated. Some elements of the ISO's present and proposed GMCs more or less adhere to this principle, while other elements are nothing other than taxes designed to raise revenue.

Following this principle, the task of designing a GMC boils down to identifying the services that customers use and identifying reasonable measures of customer use. The "services that customers use" are things that customers can measurably affect, not the activities that producers perform. Thus, while a transmission system operator performs many activities that together assure system reliability, customers do not use a vaguely defined and unmeasurable "reliability service." What transmission system customers *do* use are the system operator's power balancing services and flow management services, both of which are measurable and are subject to at least some customer control; and it is the competence with which the system operator performs these measurable services that together constitute virtually all of what is meant by "reliability."

The Stakeholder Process

Since October 2002, the ISO has conducted a comprehensive stakeholder review process to evaluate the entire GMC as directed by the FERC Administrative Law Judge on May 10, 2002[1] ("Initial Decision") and affirmed by the FERC in its Opinion and Order of May 2, 2003 ("Opinion No. 463").[2] The Initial Decision states that serious consideration of further unbundling of the ISO's GMC was appropriate, particularly for the Control Area Services (CAS) component, which encompasses much of the reliability services identified above, and that the ISO's current GMC rate design was only a step in developing a proper allocation of costs according to principles of cost causation.[3] The Initial Decision identified MID's proposal as one that was required to be subject to full stakeholder review in the stakeholder process.[4] MID's proposal has, as a result of the stakeholder process, been considerably refined in response to stakeholder input.

The stakeholder review process was organized through a charter that set as its primary goal to "develop and implement a GMC rate methodology that best supports the new and still changing market design in a way that achieves equity between Market Participants and provides for the collection of the ISO's revenue requirement." The charter further establishes the following rate design objectives:

- based on the principle of cost causation which charges customers for the cost of services that they use/cause
- ease of administration
- avoidance of unmanageable adverse operational impacts

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1 "Initial Decision," *California Independent System Operator Corp.*, 99 FERC ¶ 63,020 at 65,086, 65,096, Docket Nos. ER01-313, *et al.*, (May 10, 2002).

2 "Opinion and Order on Initial Decision," *California Independent System Operator Corp.*, 103 FERC ¶ 61,114 at PP. 12-15, Docket Nos. ER01-313, *et al.* (May 2, 2003).

3 *See* Initial Decision, 99 FERC at 65,086.

4 *See id.*, 99 FERC at 65,086, 65,090.

FERC Opinion No. 463

The FERC Opinion and Order focuses on establishing a "just and reasonable" rate design that accurately allocates costs to market participants based on the principles of cost causation. FERC, while approving most of the current cost allocation and rate design methods used by the ISO, recognized that significant improvement is needed in these methods to properly adhere to the principles of cost causation; and it therefore affirmed the comprehensive evaluation process required by the Initial Decision in GMC 2001. FERC expressed its limited confidence in the current design when it stated "the GMC is susceptible to further refinement," and that the "GMC rate structure is a work in progress."[5]

Furthermore, FERC recognized that different ISO customers impose different cost burdens on the ISO and that the ISO's current GMC rate design does not capture this principle, particularly the CAS component, which encompasses vaguely defined reliability services. FERC notes that "Customers with behind-the-meter generation who primarily rely on that generation to meet their energy needs have made a convincing argument that use of gross load results in this customer class being allocated too great a share of CAS costs."[6] FERC refers to "the more limited impact such customers have on the ISO's grid" and "their more limited dependence on the ISO grid."[7]

Although FERC focused on behind-the-meter situations, it clearly understood that different customers make different use of the ISO-Controlled Grid. To address FERC's concern in a coherent fashion requires a rate design that recognizes the differences between customers but assures all customers are treated equally – a design in which the billing determinants are measures of customers' use of the ISO-Controlled Grid.

Our Proposed Rate Design

In the course of the stakeholder process, we completed a fully allocated cost-of-service study of ISO activities and developed an unbundled GMC rate design proposal that is detailed in the accompanying document. Our rate design proposal satisfies the intent of FERC and the objectives set out by the ISO stakeholder process.

Consistent with the principle that customers should pay for the services they use, we functionalize costs according to the services the ISO provides to customers; and we classify certain costs to billing determinants within functions according to the proportions identified by the ISO as demand or energy. These costs are then divided by the appropriate billing determinants to derive rates.

Our proposal recovers all of the ISO costs through rates charged on three separate functions that are provided to the customers: 1) resolving energy imbalances, so that aggregate resources equal aggregate demands at every instant in time; 2) managing transmission flows, so that transmission flows do not exceed transmission capabilities; and 3) administering markets wherein customers can voluntarily trade energy, ancillary services or financial transmission rights in advance of real time.

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[5] *See* Opinion No. 463, 103 FERC at P.14.

[6] *See id.* at P.28.

[7] *See id.*

To do this, we identified and separated the ISO costs by each of these three functions and designed rates that recover these service costs in a manner that reflects the amount of each service consumed by the customer. The resulting design for each function is as follows:

Resolving Energy Imbalances. The cost of this function is directly related to the uninstructed deviations of the scheduling coordinators (SCs) in each 10-minute dispatch interval. The rate design therefore includes a demand charge based upon each SC's annual maximum absolute uninstructed deviation and an energy charge based upon the sum of each SC's uninstructed deviations.

Managing Transmission Flows. The cost of this function is related to the customers' use of the transmission system. We propose that customers' MWh power withdrawals from the ISO-Controlled Grid serve as the measure for customer use.

Administering Markets. The costs of this function should be recovered from the customers who choose to trade in these markets. Therefore, we propose using trading volumes as the billing determinant, preferably with differentiation by the service traded (e.g., energy, ancillary services, FTRs).

Our proposal does not create any administrative burden for the ISO because its billing determinants are readily available to the ISO. In addition, not only does this proposal create no operational problems, but it instead provides new incentives for the ISO's customers to behave in ways that improve power system reliability and reduce the ISO's costs. The resulting rate structure recovers the total revenue requirement for the ISO through charges that accurately reflect the cost of providing each service and, as a result, equitably and efficiently apportions cost responsibility to the customers consuming each of the services provided by the ISO. Furthermore, the method used to develop our proposal is fundamentally consistent with standard utility ratemaking practices and easily accommodates changes that may occur in the ISO's operations or California's market design.

We appreciate the Board's effort in scheduling a meeting of the Finance Committee on July 17, 2003, and look forward to the opportunity to respond to questions and comments from those Governors in attendance.

Non-confidential nature of the Modesto Irrigation District's July 10, 2003 rate proposal document

The ISO has determined that this document does not contain Confidential Material, though it is based on confidential information. Therefore, the document is not required to be marked as confidential. However, the ISO did not intend to, and does not, waive any confidentiality with respect to the underlying data.

RATE DESIGN OF THE CALIFORNIA ISO's GRID MANAGEMENT CHARGE

Laurence D. Kirsch
Ross C. Hemphill
Laurits R. Christensen Associates, Inc.

In this paper, we propose that the California ISO's Grid Management Charge (GMC) be designed so that, to the extent practicable, customers pay for the services that customer use. The principle that customers should pay for the services they use is basic to virtually all markets. Some elements of the ISO's present GMC (e.g., the Interzonal Scheduling Charge and the Market Operations Charge) more or less adhere to this principle, while other elements (e.g., the Control Area Services Charge) are nothing other than taxes designed to raise revenue.

Following this principle, the task of designing a GMC boils down to identifying the services that customers use and identifying reasonable measures of customer use. The "services that customers use" are things that customers can measurably affect, not the activities that producers perform. Thus, while a transmission system operator performs many activities that together assure system reliability, customers do not use a vaguely defined and unmeasurable "reliability service." What transmission system customers *do* use are the system operator's power balancing services and flow management services, both of which are measurable and are subject to at least some customer control; and it is the competence with which the system operator performs these measurable services that together constitute virtually all of what is meant by "reliability."

This paper shows how the California ISO's GMC can be designed so that customers pay for what they use. It provides details on the rate design proposal made by Dr. Laurence Kirsch in the California ISO's 2001 GMC proceeding[1], trying to find common ground with the tentative positions expressed by participants in the GMC stakeholders' meetings, including those expressed in the presentations by the ISO, the California Public Utilities Commission, and Southern California Edison.[2] Furthermore, this paper provides the best numbers that it is possible to produce for this rate proposal at this time, given the availability of the underlying data.

Consistent with the foregoing discussion, we functionalize costs according to the services the ISO provides to customers; and we classify certain costs to billing determinants within functions according to the proportions identified by the ISO as demand or energy. These costs are then divided by the appropriate billing determinants to derive rates.

In this paper, Section 1 discusses functionalization while Section 2 addresses allocation. Section 3 discusses some miscellaneous issues.

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[1] Docket Nos. ER01-313-000, ER01-313-001, ER01-424-000, and ER01-424-001.

[2] Phil Leiber, *ISO Conceptual Rate Structure*, February 19, 2003; *Conceptual Proposal of Southern California Edison*, February 19, 2003; *ISO Conceptual Rate Structure*, March 17, 2003; Ben Arikawa, *California ISO Rate Structure Proposal*, April 11, 2003; Karen Shea, *CPUC/EOB Modifications to CAISO 2004 GMC Rate Structure Proposal*, April 11, 2003; Ben Arikawa, *Customer Service Cost Recovery*, April 28, 2003; Ben Arikawa, *Components of Rates,* April 28, 2003, David Timson, *Example Rate Calculations*, April 28, 2003 (presented May 12); *SCE GMC Proposal Rates*, April 28, 2003; and Ben Arikawa, *ISO Rate Proposal Update*, May 12, 2003.

1. COST FUNCTIONALIZATION

We first discuss the basis on which we have defined the ISO's functions. We then present our cost assignment estimates.

1.1. Basis for Our Functionalization

System operators provide three fundamental services to their customers:[3]

- *Resolving energy imbalances*, so that aggregate resources (generation plus imports) equal aggregate demands (load plus losses plus exports) at every instant in time.
- *Managing transmission flows*, so that transmission flows do not exceed transmission capabilities.
- *Managing voltages*, so that voltages throughout the transmission system remain within limits.

While customers' use of these first two services can be measured reasonably and simply, customers' use of the third service requires substantially greater effort to measure. We therefore propose that the first two of these fundamental services – resolving energy imbalances and managing transmission flows – be the principal functions that the California ISO use for rate design purposes, and that the costs of managing voltages be included within the costs of the managing transmission flows function.

System operators can provide other services that have costs that depend upon identifiable customer actions. We believe that one set of such services merits function status:

- *Administering markets* wherein customers can voluntarily trade energy, ancillary services, or financial transmission rights in advance of real time. In principle, customers can obtain equivalent services through bilateral trades or independent brokers.

Although Dr. Kirsch proposed in the 2001 GMC proceeding that there also be a scheduling function, we do not propose such a function at this time. In that proceeding, FERC Staff

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[3] The engineering literature repeatedly states that system operators aim to minimize some set of costs subject to system constraints and private constraints, where the system constraints are the "fundamental services" listed in the text and the private constraints are managed by customers. For examples of this literature, see M.L. Baughman and S.N. Siddiqi, "Real-Time Pricing of Reactive Power: Theory and Case Study Results," *IEEE Transactions on Power Systems*, 6(1): 23-29, February 1991; D. Chattopadhyay, K. Bhattacharya, and J. Parikh, "Optimal Reactive Power Planning and Its Spot-Pricing," *IEEE Transactions on Power Systems*, 10(4): 2014-2020, November 1995; J.Y. Choi, S.-H. Rim, and J.-K. Park, "Optimal Real Time Pricing of Real and Reactive Powers," *IEEE Transactions on Power Systems*, 13(4), November 1998; Y. Dai, Y.X. Ni, F.S. Wen, and Z.X. Han, "Analysis of Reactive Power Pricing Under Deregulation", *IEEE Power Engineering Society Summer Meeting*, Cat. No. 00CH37134, pp 2162-2167, 2000, W.W. Hogan, "Markets in Real Electric Networks Require Reactive Prices," *Energy Journal*, 14(3): 171-200, 1993; M. Muchayi and M. El-Hawary, "A Summary of Algorithms in Reactive Power Pricing," *Proceedings of the IEEE Canadian Conference on Electrical and computer Engineering*, Cat. No. 95TH81031995, pp. 692-696; V.L. Paucar and M.J. Rider, "Reactive Power Pricing in Deregulated Electrical Markets Using a Methodology Based on the Theory of Marginal Costs," *IEEE Large Engineering Systems Conference on Power Engineering*, Cat. No. 01ex490, pp 7-11, 2001. In the Supporting Documents section of this package, we include copies of the articles by Choi *et al* and by Muchayi and El-Hawary.

questioned whether separate scheduling charges were consistent with FERC policy.[4] Furthermore, although we have considered adopting the ISO's proposed Forward Scheduling charge, we are not able to do so because of our doubts about the relevancy of its billing determinant to the ISO's costs of arranging schedules.[5]

The ISO Staff recognizes that resolving energy imbalances and managing transmission flows are central to the ISO's purpose. In a recent memorandum to the Board of Governors, the Staff stated the following:

> "All customers in the Control Area use the ISO Control Area services to some degree, since the ISO keeps supply and demand in balance and manages the transmission grid to avoid congestion and line overloads. Only one entity can do his. However, not all customers use these services to the same extent. Similarly, not all customers use the ISO market services, but all interact with the ISO as customers, since they receive bills and settlement statements, make account inquiries, and ask other questions."[6]

In this statement, the Staff correctly identifies the main services that the ISO performs. The Staff also touches upon the important rate design problem of measuring the extent to which customers use these services. We address this problem in Section 2.

1.2. Cost Assignments for Our Proposed Functions

To facilitate the assignment of costs to our proposed functions, the ISO provided us with a "Cost Allocation Matrix" spreadsheet similar to the one that it uses to assign costs among the service categories that it has identified for GMC ratemaking purposes. This spreadsheet required us to specify how we would assign, among our proposed functions, the costs for each of 63 ISO departments. To make our cost assignments for these 63 "direct assignment" departments, we engaged in a series of conversations with knowledgeable ISO staff. Based upon these direct assignments, the spreadsheet automatically assigned the costs of "indirect assignment"

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[4] See *Prepared Written Direct Testimony of Stephen D. Pointer*, Docket Nos. ER01-313-000, ER01-313-001, ER01-424-000, and ER01-424-001, Exhibit S-6, June 21, 2001. Pointer states "Under Order No. 888 the CAISO would be required to allow unlimited changes to a customer's hourly schedule of energy deliveries before the hour at no additional charge. I believe that Dr. Kirsch's proposal to charge customers for schedule changes is contrary to Commission policy." Emphasis in original.

[5] As we presently understand it, the ISO's proposal counts as a "schedule" each of the following: a) provision by a generator of energy output in each hour; b) provision by a generator of regulation service in each hour; c) provision by a generator of spinning reserve service in each hour; d) an SC's aggregate load behind each ISO metering point in each hour; e) an SC's export at each export point in each hour; f) an SC's import at each import point in each hour; and g) an SC's trade with another SC in each hour. It is not obvious to us that the costs of each of these "schedules" are approximately equal. For example, an SC that is responsible for a generator that schedules a constant 100 MW of energy for every hour during the next five days would be charged for 120 schedules (5 days times 24 hours per day); while another SC that is responsible for a generator that schedules a different output level every hour of the next five days, and that repeatedly changed its scheduled amounts, would also pay for 120 schedules. As another example, a generator that helps system reliability by offering regulation service would pay twice as much for Forward Scheduling Service as a generator that offers only energy.

[6] W.J. Regan, D.A. LeVine, and P. Leiber, memorandum to the Board of Governors, June 20, 2003, Attachment A, p. 2. This attachment is included among the supporting documents presented within this package.

departments to our three functions. The result is that the ISO's costs are assigned to our functions as follows:[7]

TABLE 1
OUR ASSIGNMENT OF ISO COSTS

Function	Dollars	Percent
Resolving Energy Imbalances	$ 42,433,238	17.9%
Managing Transmission Flows	128,296,398	54.0%
Administering Markets	66,870,735	28.1%
Totals	$237,600,371	100.0%

2. CLASSIFYING COSTS AND DESIGNING RATES[8]

In this section, for each of the three functions, we classify costs as energy, demand, or customer related; and we identify appropriate billing determinants for designing rates.

2.1. Resolving Energy Imbalances

The costs of resolving energy imbalances should be recovered from customers according to their uninstructed deviations. In principle, the recovery should be according to the relationship of their deviations to those of the whole system, so that (for example) a customer who contributes to system imbalances by running deficits when the system is in deficit would pay more than a customer who happens to reduce system imbalances by running surpluses when the system is in deficit.

As a practical matter, however, the billing determinants for the resolving energy imbalances function need to be simple and familiar to customers. Hence, we propose that, in each month, the billing determinants be an energy measure, a demand measure, and a customer measure. For each SC in each month, our proposed billing determinants are as follows:[9]

- *The energy measure* is the sum of the SC's absolute uninstructed deviations during each of the 10-minute intervals in that month.
- *The demand measure* is the SC's maximum absolute uninstructed deviation during the current month and the preceding eleven months. This is a non-coincident peak measure over a rolling 12-month period (i.e., 1 NCP). We propose a *non-coincident* peak measure

[7] We emphasize that the preceding figures are derived from discussions and analyses that have taken dozens of hours rather than the hundreds of hours that would be required for a more precise analysis. Nonetheless, we believe that these figures give a reasonable approximation of the figures that would be yielded by a more precise analysis.

[8] Unless otherwise indicated, billing determinant data are from the ISO spreadsheet entitled "Aggregated filling determinant data (revised 030423).xls" [*sic*].

[9] For each SC, the "absolute uninstructed deviation" is the net deviation of the whole portfolio of the SC's resources and loads, not the deviation of each separate resource and load.

because customers have much better access to information about their own peak imbalances than about total system imbalances, allowing customers to have better control over their own billing determinants.[10] We propose a demand charge based upon each SC's largest uninstructed deviation of the past 12 months because the ISO must be prepared to respond to peak imbalances even if they rarely occur.

- *The customer measure* is the number of SCs.

Because small deviations are much less costly to resolve than large deviations, we divide the energy and demand charges into two tiers. The first-tier energy charge applies to the first 5 MWh of deviation in each 10-minute interval, while the second-tier charge applies to deviations in excess of 5 MWh. Similarly, the first-tier demand charge applies to first 5 MW of maximum deviation, while the second-tier demand charge applies to deviations in excess of 5 MW. In both cases, the first-tier price will be substantially lower than the second-tier price.

Table 2 shows the billing determinants and the values that we use for purposes of calculating rates. It also shows recent values for these billing determinants during the indicated periods.[11]

TABLE 2
BILLING DETERMINANTS
FOR THE RESOLVING ENERGY IMBALANCES FUNCTION[12]

Billing Determinant	Quantity	Data Period
Uninstructed deviation energy: First Tier Second Tier	 4,873,932 MWh 11,577,685 MWh	9/01-8/02
Uninstructed deviation demand (most recent 12 months): First Tier Second Tier	 3,806 MW-months 46,319 MW-months	9/01-8/02
Number of SCs	1,562 SC-months	9/01-8/02

[10] We note that a demand charge on maximum absolute uninstructed deviations is a charge on SCs' peak *imbalances* rather than a charge on peak *loads*. Because an SC's imbalances are largely unaffected by customer switching among SCs, this approach should not raise SCE's generic concern that demand charges might be inconsistent with a market design that allows customer switching. See memorandum of Bert Hansen, February 21, 2003.

[11] Some parties to the GMC proceeding have suggested that uninstructed deviations have been falling over time and that we should therefore give greater weight to the most recent data in our dataset. We have found, however, that giving greater weight to the most recent data has virtually no effect on the billing determinants because there is no time trend in the data that are available to us.

[12] Uninstructed deviation demand data are from the ISO spreadsheet entitled "GMC Analysis Tool- 2004-MID-masked.xls", dated 4/25/03. The division of energy and demand into tiers is based upon an ISO dataset that indicates each SC's deviations in each 10-minute interval.

To establish rates, it is necessary to allocate the costs of the Resolving Energy Imbalances function to the energy, demand, and customer components. To accomplish this, we build upon two pieces of information from the ISO's GMC rate design presentation of April 11.

First, the ISO assigns \$48,355,113[13] to Energy and Transmission Services and Congestion Management Service, which are mostly variable costs that it proposes to recover through three different energy charges. It also assigns \$93,544,836 to Core Reliability Services, which are mostly fixed costs that it proposes to recover through a demand charge. Based upon the relative sizes of these figures, we propose to recover 34.1% of non-customer costs through energy charges and 65.9% of non-customer costs through demand charges. To allocate costs among the tiers within the energy and demand charges, we note that the GMC cost of an SC's uninstructed deviation is roughly proportional to the *square* of the deviation.[14]

For the customer charge, we propose to exactly follow the ISO proposal (of April 11) for a customer charge of \$500 per SC per month. We propose to recover \$125 through the Resolving Energy Imbalances function and \$375 through the Managing Transmission Flows function: these figures roughly correspond to the relative total costs assigned to each of these two functions.

Table 3 shows the costs and rates that result from the preceding allocation process.[15]

TABLE 3
RATES FOR THE RESOLVING ENERGY IMBALANCES FUNCTION

Billing Determinant	Cost	Quantity	Rate
Uninstructed deviation energy			
tier 1	\$315,695	4,873,932MWh	\$0.0648/ MWh
tier 2	\$14,077,705	11,577,685MWh	\$1.2159/ MWh
Uninstructed deviation demand			
tier 1	\$55,816	3,806MW-months	\$14.66/ MW-month
tier 2	\$27,788,773	46,319MW-months	\$599.94/ MW-month
Number of SCs	\$195,250	1,562SC-months	\$125/ SC-month

13 Equals \$30,670,132 plus \$7,667,533 plus \$10,017,448.

14 This proportionality is exact if: a) the ISO's costs of resolving energy imbalances are proportional to the variance of aggregate system uninstructed deviations; b) the costs of resolving energy imbalances should be allocated among SCs according to the covariance of each SC's uninstructed deviations with the aggregate uninstructed deviations of the whole power system; c) the uninstructed deviations of SCs are uncorrelated with one another; and d) the uninstructed deviations of each SC have a mean of zero. To the extent that these conditions are not completely correct, they will lead to imprecision only in the relative tier prices.

15 Because uninstructed deviations are subject to uncertainty and therefore forecasting errors, further refinement of proposed ratemaking process might reasonably set prices (say) 10% above the levels expected necessary to recover revenues. Any over- or under-collection of revenue requirements in one year would be reconciled through an adjustment to the following year's revenue requirement.

The level of the charges in Table 3 reflects the level of the ISO's energy balancing costs. These charges generally apply to only small fractions of the customer's load.

2.2. Managing Transmission Flows

The costs of managing transmission flows should be recovered from customers according to some measure of their use of the transmission system, including use of potentially congested facilities that lie either *between* zones or *within* zones. Since neither the power industry nor academia has yet developed a completely accurate measure of customers' use of the transmission system, we propose that this use be measured by customers' withdrawals of power from the transmission system, which in this case is the ISO-Controlled Grid.

A key consideration made in designing rates for Managing Transmission Flows is whether or not to include a demand charge with the energy charge. The arguments in favor of including a demand charge include:

a) This is a service that only the ISO can provide.

b) The ISO incurs substantial fixed costs to be able to provide this service, and it may be appropriate to recover fixed costs through a demand charge.

c) The Commission has found that "Customers with behind-the-meter generation who primarily rely on that generation to meet their energy needs... should be allocated CAS [Control Area Services] costs on the basis of their highest monthly demand placed on the ISO's grid..."[16]

The arguments against including a demand charge include:

d) The ISO's costs of managing flows are more related to system complexity (e.g., number of busses) than peak loads.

e) Demand charge cost recovery may be unrelated to customer cost causation.

f) A demand charge shifts about $6 million of costs from large SCs to small SCs.

Our proposed design for this service includes only a customer charge and energy charge because we doubt there is a significant relationship between peak customer demands on the system and the costs of managing transmission flows. Specifically, for each SC in each month, the billing determinants for this function include the following energy and customer measures:

- *The energy measure* is the sum over time of the SC's power withdrawals from the ISO-Controlled Grid.
- *The customer measure* is the number of SCs.

Table 4 shows the billing determinants and the values that we use for purposes of calculating rates. It also shows recent values for these billing determinants during the indicated periods.

[16] Federal Energy Regulatory Commission, "Opinion and Order on Initial Decision," *California Independent System Operator Corp.*, 103 FERC ¶ 61,114 at P.28, Docket Nos. ER01-313, *et al.* (May 2, 2003).

TABLE 4
BILLING DETERMINANTS
FOR THE MANAGING TRANSMISSION FLOWS FUNCTION

Billing Determinant	Quantity	Data Period
Power withdrawals	242,456,619 MWh	9/01-8/02
Number of SCs	1,562 SC-months	9/01-6/02

Table 5 shows the consequent design for this function.

TABLE 5
RATES FOR THE MANAGING TRANSMISSION FLOWS FUNCTION

Billing Determinant	Cost	Quantity	Rate
Power withdrawals	$127,710,648	242,456,619 MWh	$0.5267 / MWh net load
Number of SCs	$585,750	1,562 SC-months	$375 / SC-month

Under this rate design proposal, only flows over the ISO-Controlled Grid would be subject to the Managing Transmission Flows charge. For example, in the unusual event that a Participating Transmission Owner with a 56% ownership share of certain transmission facilities turned those facilities over to ISO control while the owners of the remaining 44% did not turn those facilities over to ISO control, then 56% of flows over those facilities would be subject to this charge.

2.3. Administering Markets

The costs of administering markets should be recovered from the customers who choose to trade in these markets. Ideally, measurement of the customers' use of these ISO services should be according to some combination of volumes (MWhs), values (dollars), and numbers of transactions. The measurement should probably differ by the service traded.

Although we understand that the ISO incurs substantial fixed costs to be able to administer markets, and although we believe that system operators are in principle well positioned to offer market services at low cost relative to competitors, we find the case for demand and customer charges to be dubious. While Resolving Energy Imbalances and Managing Transmission Flows are inherently monopoly services that a system operator must be prepared to perform at all times, the Administering Markets function is subject to substantial competition. Although this competition *may* come in the form of sophisticated power exchanges, it certainly *has* come in the form of self-provision of energy and ancillary services as well as bilateral trades in these services.

For the Administering Markets function, there are two ways in which competition undermines the rationale and practicality of demand and customer charges. First, competition implies that the system operator does not need to serve all market trades, and may in fact serve only a very small fraction of market trades. Recovering the costs of Administering Markets through fixed charges would give the system operator poor incentives to size this business function in accordance with the volume of business that it will actually serve. Second, a demand charge could undermine the system operator's competitive position by threatening to impose high costs on the customer for occasional trades, thereby discouraging the customer's participation in the system operator's markets. This is not a problem for demand charges applied to the monopoly services that the customer must purchase from the ISO.

Given the data that are presently available to us, we propose that the billing determinant for the Administering Markets function be as follows:

- *Trading volumes*, which can be measured by volumes of power traded, preferably with differentiation by the service traded.

Table 6 shows the billing determinant and the values that we use for purposes of calculating rates. The billing determinant excludes the trades that occur when the ISO resolves uninstructed deviations, as the ISO's costs for such trades are included in the Resolving Energy Imbalances function. In Table 6, trading volumes are measured by giving each MW-h of regulation traded exactly the same weight as (for example) a MW-h of spinning reserves traded. Although the experience of competitive commodity markets leads us to believe that differentiation among services is warranted, we use the aggregate MW-hs figure for the immediate purpose of this proposal.

TABLE 6
BILLING DETERMINANTS
FOR THE ADMINISTERING MARKETS FUNCTION

Billing Determinant	Quantity	Data Period
Energy trading volumes	5,406,097 MWh	9/01-8/02
AS trading volumes	23,921,072 MW-h	9/01-8/02

Assuming that the prices of energy trades should be identical to those of ancillary services trades, Table 7 shows the consequent rates.

TABLE 7
RATES FOR THE ADMINISTERING MARKETS FUNCTION

Billing Determinant	Cost	Quantity	Rate
Energy trading volumes	$12,326,784	5,406,097 MWh	$2.2802 / MWh
AS trading volumes	$54,543,951	23,921,072 MW-h	$2.2802 / MWh
FTR trading volumes	---	---	---

Table 7 separates energy trades from ancillary service trades to indicate that we want to allow an eventual future differentiation in the prices of different types of trades. The table also provides a separate line for FTR trades, indicating that we would like to eventually see a separate charge for this trading activity.

3. OTHER ISSUES

Because of inevitable forecasting errors in both costs and billing quantities, there needs to be a true-up mechanism by which any over- or under-collection in one year (or quarter) is reconciled through an adjustment to the revenue requirement of the following year (or quarter). Any true-up mechanism must comply with the Federal Power Act and must be designed and administered in such a way that it does not encourage the ISO to engage in imprudent planning or take unnecessary risks.

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Competition in the Electric Power Industry: A Perspective from New York, presented at Competition in the Electric Industry: Emerging Issues, Opportunities and Risks for Facility Operators, sponsored by the Federal Facilities Council, National Academy of Sciences, Washington, DC, May 1, 1996.

Niagara Mohawk's Multi-Year Electric Rate, Restructuring and Retail Access Proposal, presented at the 27th Annual Conference of the Institute of Public Utilities, Williamsburg, VA, December 11, 1995.

Allocation and Recovery of Strandable Costs, presented at Valuing & Recovering Stranded Costs in the New Age of Competitive Power, sponsored by The Center for Business Intelligence, Washington, DC, September 21, 1995.

Competitive Pricing Strategies to Ease the Transition, presented at Successfully Overcoming Stranded Investment in the New Competitive Power Market, sponsored by International Business Communications, Orlando, FL, May 16-17, 1995.

Recovery of Transition Costs: Will We Live to Tell About It? Presented at the Fourth Annual Electricity Conference, sponsored by the Executive Enterprises, Inc., Washington, DC, March 2-3, 1995.

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Environment Conference, Denver, CO, May 17, 1993.

Reliability Considerations in the Local Distribution of Natural Gas, presented at the 23rd Annual Conference of the Institute of Public Utilities, Williamsburg, VA, December 10, 1991.

The Impacts of Rate Design on Low Use, Low Income Electric Consumers, presented at Socioeconomic Energy Research and Analysis Conference, Baltimore, MD, June 27, 1991.

Flexible Pricing in a Competitive Electric Utility Industry, presented at Electric Utility Planning for the 90's, sponsored by the Electric Utility Consultants, Denver, CO, June 20, 1991.

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RESUME

February 2003

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Academic Background

Ph.D., University of Wisconsin, Madison, 1982, Economics
M.S., University of Wisconsin, Madison, 1979, Economics
A.B., University of California, Berkeley, 1972, Economics

Positions

Senior Economist, Laurits R. Christensen Associates, Inc., 1985-present
Consultant, Pacific Gas and Electric Company, San Francisco, 1982-1985
Research Assistant, Madison Consulting Group, Madison, 1981
Teaching Assistant, University of Wisconsin-Madison, 1978-1980
Staff Accountant, Clarence Rainess & Company, CPAs, Beverly Hills, CA, 1973-1974

Professional Experience

I specialize in economic analysis for the electric utility industry, including studies of bulk power markets, power pool operations, electric power system cost structures, and reliability costs. I have has expertise in the pricing and operating practices of U.S. independent system operators (ISOs) and has provided comments and testimony to the Federal Energy Regulatory Commission (FERC) as well as to state commissions. I have developed and applied methods for estimating the real-time marginal energy and reliability costs of both generation and transmission; have developed methods for costing and pricing unbundled ancillary services; have also evaluated the potential for market power in generation service markets, including the interaction of market power with transmission congestion; have participated in the development and implementation of pricing policies for independent power producers; has evaluated the merits of various schemes for auctioning wholesale power; and have assessed a wide variety of utility pricing practices.

Electricity Projects

Survey of Literature on and Practices for Pricing Reactive Power

Commentary on FERC's Standard Market Design

Analysis of the California Independent System Operator's Grid Management Charge

Survey of Impacts and Consequences of Locational Marginal Pricing for Hydro Generation

Weather Normalization of Loads and Revenue Requirements

Opportunities for Retail Participation in Ancillary Services Markets

The Effect of Locational Prices on Retail Pricing Options

Transmission Congestion Analysis

Commentary on the Redispatch Procedures of the Midwest Independent System Operator

Curtailable Service and Self-Generation Riders

Encouraging Demand Participation in Texas' Power Markets

Seminar on Wholesale Power Markets and Prices

The Market Power Impacts of a Generation Plant Divestiture

Design of Standby, Buyback, and Interruptible Rates

Congestion Charges in the Peruvian Power System

Development of a Purchase Power Agreement Between Generation and Distribution Firms

Seminar on U.S. Power Markets for an Asian Delegation

Analysis of the Readiness for Competition of the Retail Electricity Market in Arkansas

Analysis of an Independent System Operator's Grid Management Charge

Investigation of the Benefits of Expanded Power System Metering

Quantifying the Economic Value of Ancillary Services

Development of Competitive Retail Electricity Products

New Strategies for Electricity Product Development and Wholesale Pricing

Consumer Benefits of Integrating the Generation and Transmission Assets of Municipal Utilities and Investor-Owned Utilities

Rate Structure Optimization

A New Strategic Direction In Retail Electricity Product Development and Pricing

Market Power Study of PG&E's Proposed Divestiture Of Hydroelectric Assets

Electric Cost-of-Service and Rate Design Study

Redesigning Distribution Tariffs for Restructured Electric Power Markets

Managing Transmission Risk

Comprehensive Review and Revision of Electric Rates

Shaping of Electric Energy Tariff Policy

Software for Developing Profitable Retail Product Mixes

Software for Reserve Costing and Generation Unit Scheduling

Dynamic Pricing and the Future of Distributed Generation

Development of Market-Based Pricing Products

Pricing Issues in California's Restructured Electricity Market

Survey of Unbundled Electric Power Services

Costing and Pricing Ancillary Services

Developing New Electricity Products in a Restructured Electricity Market

Retail Pricing of Electric Power in a Competitive Market Environment

Pricing Risk

Review of Draft Ancillary Service Tariffs

The Pricing of Unbundled Electric Power Services

Ancillary Services and the Organization of Electric Power Markets

Pricing Retail Electricity Financial Services

Including Marginal Reliability Costs In Real-Time Prices

Real-Time Pricing Program Development

Costing and Pricing Transmission and Distribution Services

Market Restructuring for Retail Access

Regulatory Reform in Response to Emerging Competition

Retail Market Management and Service Design

Directions for Reactive Power Price Reform

Transmission Pricing Policy

Retail Market Management and Service Design

Transmission Pricing Strategies

Real-Time Pricing Implementation Study

Managing Electric Power Generation in a Competitive Market Environment

A Plan for Reforming the Price Structure of the New York Power Pool

Design, Implementation, and Evaluation of Real-Time Pricing

Real-Time Pricing Assessment Study

Forecasting and Measuring Hourly Marginal Costs of Electricity

The Use of Rate Design to Achieve DSM Goals

Economic Impacts of Electricity Cost Shocks

Design and Analysis of a Real-Time Pricing Program

Inclusion of Transmission Reliability Costs in Real-Time Pricing Decisions

Commercial and Industrial Market Management

Development of an External Cost Indexing Incentive Plan

Forward and Options Contracts for Electric Power

Comparative Assessment of Alternative Regulatory Reform Proposals

Dynamic Pricing of Decentralized Power Systems

Design of a Voluntary Time-of-Use Rate for Residential Customers

Design and Testing of Real-Time Pricing Structures for Supplemental Electric Service

Evaluation of Proposed Nuclear Performance Incentive Plans

A Field Test of Priority Service Pricing

Program Design and Implementation for Voluntary Interruptible Service

Design of Retail Electricity Rates for Efficiency and Profitability

Survey of Recent Developments in U.S. Curtailable Power Service Programs

Cost-Benefit Analysis of Seasonal Time-of-Use Peak-Activated and Interruptible Rates

Estimation of the Load Relief Provided by an Interruptible Service Program

Efficient Pricing of Transmission Services

Analysis of the Feasibility of Real-Time Pricing in the State of Maryland

Costs and Benefits of Alternative Wholesale Electricity Supply Strategies

Analysis of Household Load Response to Voluntary Time-of-Use Rates

Design of an Experimental Real-Time Pricing Program

The Interaction of Time-of-Use Rates and Energy-Using Technologies: The Case of Residential Heat-Pumps

Real-Time Pricing of Power Purchases from Cogenerators and Small Power Producers

Marginal Shortage Costs and Avoided Cost Payments to Qualifying Facilities

Other Projects

Price Cap Design and X Factor Estimation for Peruvian Telecommunications Regulation

Review of Pharmaceutical Economics

Commentary on FERC's Gas Rate Design Mega-NOPR

Evaluation of the Price Escalation Clauses of a Long-Term Coal Supply Contract

Bell Operating Companies' Marginal Operating Costs for Interstate Switched Access and Private Line: An Econometric Model

Oil Inventory Economics

The Marginal Cost of Gas Service

The Economic Theory of Enhanced Natural Gas Service to the Industrial Sector

Testimony

Affidavit on the Proposed Mitigation Measures of the Midwest Independent System Operator, on behalf of the Midwest Transmission Dependent Utilities, before the Federal Energy Regulatory Commission, Docket No. ER03-323-000, January 2003.

Affidavit on Supply Margin Assessment and Other Market Power Metrics, on behalf of the American Public Power Association and the Transmission Access Policy Study Group, before the Federal Energy Regulatory Commission, Docket Nos. PL02-08-000 and Docket No. RM01-12-000, October 2002.

Affidavit on the Proposed Congestion Management and Redispatch Cost Allocation of the Midwest Independent System Operator, on behalf of the Midwest Transmission Dependent Utilities, before the Federal Energy Regulatory Commission, Docket No. ER02-1767-000, May 2002.

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Testimony on the Grid Management Charge of the California Independent System Operator, on behalf of the Modesto Irrigation District, before the Federal Energy Regulatory Commission, Docket Nos. ER01-313-000, ER01-313-001, ER01-424-000, and ER01-424-001, March 2001.

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Testimony on the Pricing of Buyback Power, on behalf of the Niagara Mohawk Power Corporation, before the New York Public Service Commission, Case Nos. 94-E-0912 and 94-E-1075, 1995.

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"Pricing The Grid: Comparing Transmission Rates Of The U.S. ISOs," *Public Utilities Fortnightly*, February 15, 2000.

"Developing and Pricing Distribution Services," in *Pricing in Competitive Electricity Markets*, A. Faruqui and K. Eakin, eds., Kluwer Academic Press, Amsterdam, 2000 (with R. Camfield).

Managing Transmission Risk, Report TR-114276, Electric Power Research Institute, Palo Alto, December 1999 (with F. Alvarado and R. Rajaraman).

"ISO Economics: How California Flubbed It on Transmission Pricing," *Public Utilities Fortnightly*, October 15, 1998.

Dynamic Pricing and the Future of Distributed Generation, E SOURCE, Boulder, Colorado, September 1998 (with D. Armstrong and C. L. M. Braithwait).

"Unbundling Electric Discos," *Public Utilities Fortnightly*, 136(7), pp. 40-45, April 1, 1998 (with A. Faruqui).

"Profiting from Operating Reserves," *The Electricity Journal*, 11(2), pp. 40-49, March 1998 (with R. Rajaraman).

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Costing and Pricing Electric Power Reserve Services, Report TR-108916, Electric Power Research Institute, Palo Alto, December 1997 (with R. Rajaraman and C. Clark).

Preparing the Ground for Pricing Unbundled Electricity Services: The Importance of Markets, Report TR-106933, Electric Power Research Institute, Palo Alto, November 1996.

Developing Unbundled Electric Power Service Offerings: Case Studies of Methods and Issues, Report 40-96-31, Edison Electric Institute, Washington, October 1996 (with L. Kaufmann).

“Retail Pricing of Reactive Power Service,” *Proceedings: 1996 EPRI Conference on Innovative Approaches to Electricity Pricing*, Report TR-106232, Electric Power Research Institute, Palo Alto, March 1996 (with F.L. Alvarado, R. Broehm, and A. Panvini).

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“Practical Barriers to Efficient Wholesale Pricing,” *Proceedings: 1994 Innovative Electric Pricing*, Report TR-103629, Electric Power Research Institute, Palo Alto, February 1994.

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“Reserve Costs,” EPRI Ancillary Services Conference, Nashville, November 2002.

“Problems with Wholesale Market Design That Foul Up Retail Markets,” Connecting Wholesale and Retail Electricity Markets Conference, Denver, August 2002.

“Designing and Pricing Reserve Services,” Edison Electric Institute Transmission Pricing School, Madison, Wisconsin, July 2002.

“The Pennsylvania – New Jersey – Maryland Power Market”, Edison Electric Institute Transmission Pricing School, Madison, Wisconsin, July 2002.

“Issues in the Standard Market Design of Ancillary Services,” Ancillary Services Conference, Denver, April 2002.

“Performance-Based Regulation for Transmission,” Edison Electric Institute Transmission Pricing School, Madison, Wisconsin, July 2001.

“Transmission Congestion Pricing: California Versus the Northeast”, Edison Electric Institute Transmission Pricing School, Madison, Wisconsin, July 2001.

"Replacing Markets With Capacity Requirements," Harvard Electricity Policy Group Plenary Session, Cambridge, Massachusetts, June 2001.

"How Transmission Affects Market Power in Reserve Services," Workshop on Markets for Electricity, Economics and Technology: A Flow-Based Paradigm for Systems Operation and Market Coordination, Stanford University, August 2000 (with K. Eakin and R. Rajaraman).

"Transmission Pricing in ISO New England," Edison Electric Institute Transmission Pricing School, Madison, Wisconsin, June 2000.

"Transmission Pricing in the New York ISO," Edison Electric Institute Transmission Pricing School, Madison, Wisconsin, June 2000.

"Emerging Opportunities in Ancillary Services," EPRI-GRI Seminar on Energy Markets and Generator Response, Miami, November 1999.

"Profitable Generator Response to Uncertain Energy and Reserve Prices," Ancillary Services Conference, Denver, September 1999 (with F. Alvarado and R. Rajaraman).

"Profitably Responding to Energy and Reserve Prices," Infocast Conference on Ancillary Services Markets, Philadelphia, March 1999 (with F. Alvarado and R. Rajaraman).

"Managing Transmission Risks," Power Marketing Association's Fifth Annual Meeting, Washington, November 1998 (with F. Alvarado and R. Rajaraman).

"Valuing Capacity Benefit Margin," Edison Electric Institute Transmission Policy Task Force Meeting, Orlando, November 1998 (with R. Rajaraman).

"Interaction Between Energy And Reserve Prices: Profit-Maximizing Commitment and Dispatch," Ancillary Services Conference, Denver, October 1998 (with R. Rajaraman).

"Costing and Pricing Reserve Services," Ancillary Services Conference, Denver, October 1998 (with R. Rajaraman).

"Comparative Transmission Pricing Policies of the U.S. ISOs," Transmission Pricing Conference, Denver, June 1998 (with A. Faruqui).

"Developing and Pricing Distribution Services," EPRI Conference on Pricing Energy in a Competitive Market," Washington, June 1998 (with R. J. Camfield).

"Measuring, Costing, and Pricing Reserve Consumption," Workshop on the Measurement and Costing of Ancillary Services in Emerging Market Structures, Miami, December 1997 (with R. Rajaraman).

"Survey of Current Reserve Costing and Pricing Practices," Power Markets and Resource Management Conference on Making Money in Energy Markets, Houston, October 1997.

"Unbundling Electric Power Distribution Services Abroad and In Other Industries," International Business Communications Workshop on Unbundling the Energy Disco, San Francisco, September 1997 (with A. Faruqui).

"Defining, Packaging, and Pricing Reserve Services," Electric Power Research Institute Workshop on Reserve Services, August 1997 (with R. Rajaraman).

"Pricing Operating Reserves," International Business Communications Workshop on Retail Electricity Prices, Atlanta, February 1997.

"Analyzing Market Power in a Deregulated Electricity Market," 17th Annual North American Conference of the U.S. Association of Energy Economists and the International Association of Energy Economists, Boston, October 1996 (with T. E. McClive and R. C. Hemphill).

"Taxonomies of Electric Power Services" and "Marginal Costs of Ancillary Services," Workshop on *Developing State-of-the-Art Marginal Costing Capabilities*, Denver, June 1996.

"Comparison of Methods for Estimating Real-Time Marginal Costs," prepared for the Real-Time Pricing Practitioners' Workshop, New Orleans, March 1993.

"Dynamic Pricing of Decentralized Power Systems," prepared for the Electric Power Research Institute, July 1990 (with D. W. Caves and P. E. Schoech).

"Considering Transmission Reliability in Pricing Electricity Services," presented at the 19th Annual Meeting of the Illinois Economic Association, Chicago, October 1989 (with D. Ray and R. Stevenson).

"Rate Design for Real-Time Pricing of Electricity," presented at the Rutgers University Advanced Workshop in Public Utility Economics and Regulation, Sagamore, New York, May 1987 (with L. R. Christensen, D. W. Caves, and B. F. Neenan).

"Interpretation of Experimental Results and Implications for Cost Effectiveness," presented at *Proceedings of Niagara Mohawk Workshop on Real-Time Pricing and Load Management Opportunities in New York State*, March 1986 (with D. W. Caves).

"Overview of Electricity Pricing and Service Options," presented at *Proceedings of Niagara Mohawk Workshop on Real-Time Pricing and Load Management Opportunities in New York State*, March 1986 (with D. W. Caves).

"Rate Modeling for Competitive Markets," presented to the American Gas Association Rate Committee Meeting, Orlando, Florida, September 1985.

"The Fundamentals of Gas Marginal Costing," presented to the National Economic Research Associates' Marginal Cost Working Group, San Diego, California, February 1984.

SUMMARY OF SUPPORTING DOCUMENTS

This section presents copies of three documents that affirm and support our position that the core services provided by system operators are resolving power imbalances and managing transmission flows.

The first document that we present is an attachment to the June 20, 2003 memo to the Board of Governors from the ISO Staff.[1] Near the top of page 2, this document identifies the two main services that the ISO provides, namely that it "keeps supply and demand in balance and manages the transmission grid to avoid congestion and line overloads." This observation by ISO Staff is consistent with our assertion that virtually everything that a system operator does is directly or indirectly related to these two services.

This is a widely held view of power systems engineers around the world. In footnote 3 of our technical paper, we list several articles that explicitly rely on the fact that system operators are in the business of minimizing some set of costs subject to system constraints (e.g., power balance, flow limits, voltage limits), and that there are also private constraints (e.g., generator limits) that in a competitive market are managed by private parties. Although the subjects of these articles are diverse, each and every one is based upon the universally accepted fact that a system operator resolves power imbalances and manages transmission flows.

For your convenience, we provide two of the articles mentioned in footnote 3. In each article, the core services provided by a system operator appears in the mathematics as follows:

- Choi *et al* say that power system operators maximize the net benefits of electricity subject to constraints on the power balance, transmission flows, voltages, and various private constraints. In the article, the cost function (included in the net benefits of electricity) appears in equation 4; the power balance constraints appear in equations 6 and 7; transmission flow limits appear in equations 13 and 14; voltage limits appear in equation 15; and private constraints appear in equations 8 through 11.
- Muchayi and El-Hawary say that power system operators minimize the costs of electricity subject to power balance, transmission flow, voltage, phase angle, and various private constraints. In the article, the cost function appears at equation 4; the power balance constraints appear in equations 5 and 6; transmission flow limits appear in equations 9 and 10; voltage limits appear in equation 11; phase angle limits appear in equation 12; and private constraints appear in equations 7 and 8.

Because system physics dictate the requirements for managing transmission systems, and because these physics are the same all over the world, it is not surprising that the articles listed in footnote 3 were variously written by engineers at research and academic institutions in Brazil, Canada, China, India, Korea, and the U.S. In other words, the management of power balance, flow limits, and voltage limits is a necessity for system operators everywhere, and are the fundamental services that system operators provide to their customers. Our rate design proposal thus relies on the same understanding of the system operator's role as underlies the discussions of these articles.

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[1] W.J. Regan, D.A. LeVine, and P. Leiber, memorandum to the Board of Governors, June 20, 2003, Attachment A.

Summary of a Cost-of-Service Study and its Use to Allocate and Recover Costs

The **rate design** process involves determining the **charges** that will recover the costs that are associated with each of the various services (called "functions" in cost-of-service language) provided, by spreading them across an appropriate measure of the type of usage associated with each function. In other words, a charge is developed which, when multiplied by a customer's usage of an appropriate type, will recover, as closely as possible, a customer's obligation for the costs incurred providing that function. (All costs are considered recoverable in this process and the charges are set to meet the total budget of the company, in this instance, the ISO. Disputes over the level of costs are taken up in the budget process.)

A **cost-of-service study** generally looks at accounting costs, i.e., costs recorded in a utility's accounts. The ISO uses the costs in its budget to establish its cost of service.

The study first sorts all of the accounting costs (the ISO cost center budgets) into **functions.** For an electric utility, these functions would be generation, transmission, distribution, and customer services. An ISO provides a subset of traditional utility services and some new ones. A detailed analysis of the activities that cause the ISO to incur costs resulted in the identification of the following functions:

1) **Control Area Services**, which may be subdivided into fixed and variable-cost services. The ISO has made a proposal to split this function into:
   - Core Reliability Services -- those activities that are essential to the functioning of the ISO as a Control Area Operator in a Control Area of its size and geography, and
   - Energy and Transmission Services -- those activities that vary with the intensity of use of the Control Area
2) **Market Services**, which the ISO proposes to subdivide into:
   - Congestion -- the management and operation of Inter-Zonal congestion markets,
   - Market Usage -- the management and operation of the forward and Real-Time Markets, and
   - Scheduling -- the forward scheduling of Energy and Ancillary Services and the processing of accepted Ancillary Services bids, and

3) **<u>Settlements, Metering and Client Relations</u>**, which includes those activities relating to interaction with ISO customers.

All customers in the Control Area use the ISO Control Area services to some degree, since the ISO keeps supply and demand in balance and manages the transmission grid to avoid congestion and line overloads. Only one entity can do this. However, not all customers use these services to the same extent. Similarly, not all customers use the ISO market services, but all interact with the ISO as customers, since they receive bills and settlement statements, make account inquiries, and ask other questions.

<u>Classification of Costs</u>

The next part of the process is to identify the usage patterns that drive the costs associated with the functions. This process is called **classification**. For some purposes, the ISO's costs are driven by the need to meet the maximum instantaneous usage of the Control Area by any and all participants. Others are driven by how the services are used over time and how much customers deviate from what they have scheduled. Still others are driven by the numbers of customers the ISO has. These usage patterns determine who is responsible for the ISO's costs and thus how these costs are to be allocated among customers. They also provide the basis for billing the customers for the recovery of these costs.

The functions are classified as to whether they relate to:

- Demand (i.e. instantaneous use of the Control Area at any given time or at the time of system peak),
- Energy (i.e. cumulative use of the Control Area over time and often referred to as "Load"), and/or
- Customer (i.e. interaction with the customers, in this case, Scheduling Coordinators) costs.

<u>Billing Determinants</u>

The actual usage patterns that define the classification are used to develop what are called billing determinants. These include kW of instantaneous Demand (either the maximum at any time (non-coincident peak) or, for some purposes, at the time of system peak (coincident peak)), kWh of Energy (volumetric usage of the system), and number of customers. The kWh of Energy can be net or gross (i.e. they can include load behind-the-meter or not) or they can be assessed, if appropriate from a cost causation perspective, in terms of what the customer has scheduled (e.g. as deviations from the final schedule). The billing determinants are the measurements of usage, which will be used to bill the customers for the costs they have been allocated.

Assignment of Costs

It is not always easy to determine which costs are most appropriately assigned to each service or function, or which type of usage best characterizes responsibility for these costs. Some assignments are inherently difficult. For example, the scheduling infrastructure systems are mainly used to schedule but also are used to process Ancillary Services bids and for Congestion Management. The latter category are called **joint costs**, in that the fixed (investment) costs of the system support three functions. In such cases some degree of judgment must be used in assigning the costs of the investment to the different functions, since systems were not developed on an individual functional basis and the costs were not tracked that way. Similarly, the infrastructure and personnel providing control area services must include the equipment and staff to provide some services instantaneously (e.g. assuring that the transmission lines are not overloaded or that there is check-out at the interties) regardless of how intensively the Control Area is being used at any given hour and to do so 24 hours a day. At the same time, the number of personnel needed for Control Area services will vary with the amount of activity taking place at a particular time. For instance, when the level of imports and exports is high, there is significantly greater check-out activity with adjacent Control Areas, which may be accompanied by contingencies that increase the amount of effort required to complete each check-out.

Finally, there are **overhead costs**, such as general and administrative costs, that can only be assigned on the basis of some convention, generally referred to as "allocation". These costs may only be very indirectly associated with specific ISO activities, but ultimately support all ISO functions. An allocation may assign overheads on the basis of total dollars, labor costs, or some combination of factors. The more costs that can be directly assigned to functions the better, but there will always be costs, such as human resources management, information systems support, etc., that are shared throughout the organization. Therefore, some costs will always be allocated as overhead.

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See Choi, S.-H. Rim, and J.-K. Park, "Optimal Real Time Pricing of Real and Reactive Powers," *IEEE Transactions on Power Systems*, 13(4), November 1998.

Due to copyright limitations, we cannot provide an electronic copy of the article for access on this website.

M. Muchayi and M. El-Hawary, "A Summary of Algorithms in Reactive Power Pricing," *Proceedings of the IEEE Canadian Conference on Electrical and computer Engineering*, Cat. No. 95TH81031995, pp. 692-696

SCE GMC PROPOSAL UPDATE

1) SCE developed a GMC proposal and presented it to the 2004 GMC Stakeholder group.

2) The May 2, 2003 FERC Final Order in the ISO's 2001 GMC case provides guidance that SCE believes is appropriate to consider in developing the 2004 GMC.

- A demand charge applied to "Grid Demand" would be a non-discriminatory and comparable way to charge for Control Area Services.
- Grid Demand is defined to be the demand that a Scheduling Coordinator places on the ISO Grid.
- A Grid Demand charge would eliminate the issue of estimating retail behind-the-meter load.
- A grid Demand charge would eliminate the issue of which party should be billed for all retail and wholesale behind the meter load.

3) The Final Order guidance is applicable to both the SCE and the ISO's GMC proposals, in the sense that each would need to be modified to be consistent with the Final Order.

4) In light of the Final Order guidance, and other long-standing SCE issues that were incorporated within SCE's GMC proposal, SCE is willing to support the ISO proposal if the following modifications are made to it:

a) The ISO should use a billing determinant of Grid Demand for the Core Reliability Services (CRS) charge)

b) Grid Demand should be measured comparably for all entities.

   - If an SC has load and generation on a distribution circuit, that should not contribute to the GMC Grid Demand billing determinant.
   - Grid Demand should include exports, but exports should not include any Mohave Participant energy, SWPL energy, or COTP energy (anything delivered to other control areas over non-PTO transmission).

c) The Energy and Transmission Services (ETS) charge should be assessed only to exports that use the ISO controlled grid.

d) The billing determinant for the ETS charge should not include an SC's distribution-level load served by distribution-level generation.

e) In the event that exports are determined to include energy that is the load responsibility of another control area delivered over non-PTO transmission facilities, there should be appropriate treatment for the CRS and ETS charges: an assessment equal to 10% of these rates.

CALIFORNIA ISO GRID MANAGEMENT CHARGE

CONCEPTUAL PROPOSAL of SOUTHERN CALIFORNIA EDISON

2004 GMC STAKEHOLDER PROCESS

February 19, 2003 Stakeholder Meeting

SCE submits the following initial conceptual proposal for the design of the ISO's Grid Management Charge for the year 2004 for consideration in the "2004 GMC Stakeholder Process".

CONCEPTUAL PROPOSAL

The ISO Grid Management Charge (GMC) would consist of a total of five charges for distinct ISO services. These five charges are as follows:

1) A Control Area Services (CAS) charge;
2) A Dynamic Dispatch Export Service (DDES) charge;
3) A Scheduling Service (SS) charge;
4) A Market Operations Service (MOS) charge; and
5) A Real-Time Market Operations Service (RMOS) charge.

The SCE proposal has two groups of charges: 1) Charges related to the provision of reliable control area operations (includes the CAS and DDES charges); and 2) Charges related to the provision of additional ISO services (includes the SS, MOS, and RMOS charges). Each MWh utilizing the ISO grid pays one of the charges relating to control area operations and one related to the provision of additional ISO services. The following figure represents this rate design framework:

<table>
<tr><th colspan="5">SCE CONCEPTUAL PROPOSAL FOR GMC RATE DESIGN</th></tr>
<tr><th colspan="2">Provision of Reliable Control Area Operations</th><th colspan="3">Provision of Additional ISO Services</th></tr>
<tr><td colspan="2">Two Charges related to reliable control area operations.

Customer pays CAS unless eligible for DDES</td><td colspan="3">Three charges related to provision of additional ISO services.

Customer pays one of the three for any energy, depending on service required:
1) Schedule ▶ SS charge
2) Market ▶ MOS charge
3) Uninstructed Imbalance ▶ RMOS charge</td></tr>
<tr><td>CAS</td><td>DDES</td><td>SS</td><td>MOS</td><td>RMOS</td></tr>
</table>

The following sections present a more detailed description of the services, the costs to be allocated to each service, and the billing determinants that would be used to develop each charge. Table 1 below presents an overall summary description of the SCE conceptual proposal.

DESCRIPTION OF SERVICES

Following is a description of the five services:

1) Control Area Services

The Control Area Service (CAS) service is the service that the ISO provides to all control area load in ensuring safe and reliable operation of the transmission grid and dispatch of bulk power supplies.

2) Dynamic Dispatch Export Service

The Dynamic Dispatch Export Service is the service that the ISO provides to generation within the ISO control area that is dynamically dispatched[1] to other control areas over transmission owned by other entities. This service is taken in lieu of "Control Area Services" to qualifying dynamically dispatched export energy.

3) Scheduling Service

The Scheduling Service is the service that the ISO provides to market participants by including their energy or ancillary services schedules in the ISO's day-ahead or hour-ahead aggregate schedule, ensuring that the market participant may produce and transmit energy or withdraw energy from the grid if the schedule is accepted, avoiding other charges related to market operation.

4) Market Operations Service

The Market Operations Service is the service that the ISO provides to market participants that participate in any day-ahead, hour-ahead ISO market, or supplemental energy market, both for energy and for ancillary services.

5) Real-Time Market Operations Service

The Real-Time Market Operations Service is the service that the ISO provides to market participants that have uninstructed imbalances. This service allows the participant to balance its aggregate supply and load.

---

[1] Dynamically dispatched energy is exported from one control area to another such that the responsibility for the resource performance is also transferred to the receiving control area.

COSTS ALLOCATED TO EACH SERVICE

Following is a description of the costs that would be allocated to each service:

1) Control Area Services

Costs that the ISO incurs in providing reliable operation of the grid. These would include the same costs that are allocated to the current CAS, plus those costs currently allocated to the interzonal congestion charge that are related to control area services, but less the costs of scheduling. It would also exclude costs explicitly allocated to DDES.

2) Dynamic Dispatch Export Service

The subset of costs allocated to CAS that can be identified as benefiting those entities taking DDES service.

3) Scheduling Service

All costs of scheduling, plus the costs of running day-ahead and hour-ahead transmission models to check for and resolve congestion on a day-ahead and hour-ahead basis.

4) Market Operations Service

The costs of operating ISO markets.

5) Real-Time Market Operations Service

The costs that the ISO incurs in managing real-time imbalances.

BILLING DETERMINANTS FOR EACH SERVICE

Following is a description of the billing determinants that would be used to develop the rate design for this GMC proposal and also would be used to bill customers when the proposal was implemented:

1) Control Area Services

MWh of Control Area Load, less energy qualifying for DDES. Control Area Load would not include retail behind-the-meter load served by behind-the meter generation.

2) Dynamic Dispatch Export Service

MWHs of generation dynamically dispatched to other control areas over the transmission lines owned by other entities.

3) Scheduling Service

MWhs of energy scheduled, plus MWh of self-provided ancillary services.

4) Market Operations Service

MWhs of energy or ancillary services purchased or sold in ISO markets.

5) Real-Time Market Operations Service

MWhs of uninstructed imbalance energy.

RATE DESIGN and DETERMINATION OF RATES

All of the rate components would be charged on an energy basis ($/MWh). There are two groupings of the rate components: 1) the CAS and DDES rates; and 2) the SS, MOS, and RMOS rates. The rates for the services within each of these groups would be determined simultaneously, as discussed below:

CAS and DDES

A customer must take either CAS service or DDES service, and is only eligible for DDES if it possesses a qualifying resource. To SCE's knowledge, the Mohave generation unit is the only resource that would qualify. The billing determinant for the DDES would be that portion of the Mohave unit that is dynamically dispatched to Nevada and SRP's control areas. The billing determinant for the CAS would be the remainder of Control Area Load.

The rate for the DDES would be calculated as the costs allocated to DDES divided by the amount of energy eligible for this service. The rate for the CAS is then calculated as the costs allocated to the CAS divided by the Control Area Load less the amount of energy eligible for DDES.

ESC, MOC, and RMOC

A customer must take either Scheduling Service (SS), Market Operations Service (MOS), or Real-Time Market Operations Service (RMOS) for any energy withdrawn from the grid.

These three services are services of increasing value to participants and increasing cost to the ISO, so the rate design should result in the SS rate being the lowest, the MOS rate being higher, and the RMOS rate being the highest.

SCE proposes that the rates be developed in an additive fashion for these three GMC rate components. The SS rate would be calculated as the costs allocated to the SS service divided by the total MWh withdrawn from the grid. The MOS rate would be calculated as the costs allocated to the MO service divided by the MWh that were not scheduled (were in the market or were an uninstructed deviation), plus the Energy Scheduling Service rate. The RMOS rate would be calculated as the costs allocated to the RMO service divided by the MWh of uninstructed deviations, plus the MOS rate.

Following is an example of the determination of rates for these three GMC components:

Service	**Allocated Costs**	**Billing Determinant**	**Individual Rate Component**	**Total Rate for Service**
Scheduling	$20	120 MWh	$0.10 =$20/(120+60+20)	$0.10
Market Operations	$60	60 MWh	$0.75 =$60/(60+20)	$0.85 =$0.10+$0.75
Real-Time Market Operations	$20	20 MWh	$1.00 =$20/20	$1.85 =$0.10+$0.75+$1.00
Totals:	$100	200 MWh		

Total revenues collected would equal $100 if the actual billing determinants were equal to the forecast billing determinants, which is equal the costs allocated to these services:

Scheduling Service Revenues of $12 (Rate of $0.10 times 120 MWh)
Market Operations Service Revenues of $51 (Rate of $0.85 times 60 MWh)
Real-Time Market Operations Service Revenues of $37 (Rate of $1.85 times 20 MWh)

COMPARISON TO EXISTING GMC STRUCTURE

The existing ISO GMC structure consists of three charges: the Control Area Services charge, the Congestion Management charge, and the Ancillary Services and Real-Time Operations charge. In general, SCE's initial conceptual proposal unbundles the existing CAS charge into the two charges, a CAS and a DDES; and also unbundles the ASREO charge into three separate charges, the ES, MOC, and RMOC charges. It eliminates the existing Congestion Management charge, moving costs associated with congestion management into all of the other charges. With the anticipated move to a LMP congestion management system when MD02 is implemented in 2004, a separate congestion management charge is not viable, since there is no satisfactory method of measuring "use" of congestion management by a customer.

TABLE 1

GMC Rate Component	Description of Service	ISO Costs to be Allocated to Service	Billing Determinant
Control Area Services (CAS)	ISO provision of reliable control area operations	Basically same as CAS now, plus some of the costs that are now allocated to congestion management.	MWh of Control Area Load (not including retail BTM)
Dynamic Dispatch Export Service (DDES) (i.e., Mohave)	ISO provision of reliable service to generation dynamically exported to other control areas over transmission owned by others.	Subset of CAS costs that DDES resources use.	MWhs of Generation dynamically dispatched to other control areas over transmission owned by others.
Scheduling Service (SS)	ISO inclusion of scheduled generation, load, or ancillary services in DA or HA schedules	Costs of scheduling, plus running DA and HA transmission models to check for congestion (much of what is now congestion management)	MWHs of scheduled energy or self-provided AS
Market Operations Service (MOS)	Participation in ISO markets, including: 1) DA+HA energy 2) AS markets 3) Instructed imbalances	Costs of ISO markets, as well as all costs allocated to SS component.	MWh of purchases or sales of energy or AS from ISO markets.
Real-Time Market Operations Service (RMOS)	Provision of reliable grid operations by the ISO, including balancing of aggregate supply and demand, as affected by real-time uninstructed imbalances.	All costs allocated to SS and MOC, plus ISO costs incurred in managing real-time imbalances.	MWh of uninstructed imbalance energy

GMC PROPOSAL

Southern California Edison

July 17, 2003

SCE Objectives

The GMC should:

1) Reflect cost-causation and benefits received
2) Be consistent with FERC direction
3) Be fair and non-discriminatory to all market participants
4) Be as simple as possible
5) Reflect uniqueness of energy serving load in other control areas delivered over non-ISO Controlled Grid facilities

SCE ROLE IN GMC STAKEHOLDER PROCESS

- SCE has actively participated in the ISO's 2004 GMC stakeholder process
- SCE developed its own GMC proposal and presented it to the group in February
  - Four GMC buckets:
    - Control Area Services
    - Scheduling
    - Market Operations Service
    - Real-Time Imbalances Service
  - All four buckets would be charged on an energy basis ($/MWh).
  - Energy serving load in other control areas delivered over non-ISO Controlled Grid facilities, not the load responsibility of the ISO, would pay 10% of Control Area Services charge.

FERC 2001 GMC Decision

- On May 2, FERC issued a Final Order in the ISO's current 2001 GMC case (remains subject to rehearing)
- The Final Order requires a demand charge for the Control Area Services (CAS) charge for certain customers with behind-the-meter load.
  - Wholesale and retail behind-the-meter customers that have generators with a greater than 50% capacity factor
- SCE believes that the Final Order should guide the development of the 2004 GMC:
  - The "Core Reliability Services" (equivalent to the CAS) component of the GMC should be charged on a demand basis, not an energy basis, to all customers
  - The demand charge should be assessed on a non-discriminatory basis based on the Scheduling Coordinator's demand placed on the ISO Controlled Grid ("Grid Demand").

The ISO Staff Proposal Does Not Reflect the 2001 GMC Decision Guidance

The Core Reliability Services (CRS) charge, although assessed on a demand charge basis, defines demand differently than the Final Order.

- Assessed to Non-Coincident Peak Demand (includes all behind-the-meter load of retail and wholesale entities)
- Final Order defines demand as that "placed on ISO's grid" (does not include behind-the-meter load)

Current SCE Position

SCE is willing to support the ISO Staff's GMC proposal if the following modifications are made:

1) Comparable billing determinant measurement for the CRS and ETS charges (all behind-the-meter load treated comparably)

2) Appropriate consideration of unique aspects of energy that serves load in other control areas delivered over non-ISO Controlled Grid facilities, which is not the load responsibility of the ISO:

   a) Preferred: Provide a definition for "Exports", which does not include non-SCE Mohave energy.

   b) Alternative: 90% discount of CRS and ETS rates to non-SCE Mohave energy.

Comparable Billing Determinants Are Required

Core Reliability Services (CRS): “Grid Demand”

Energy and Transmission Services (ETS): “ISO Grid Energy”

Issue: How can Grid Demand and ISO Grid Energy be measured comparably in the case of large IOUs?

Proposed Billing Determinant Measurement for CRS and ETS

In the simple case of a small municipal utility with a single meter located at its city-gate, demand is measured by that meter.

In the case of SCE, which has multiple distribution lines serving loads from the ISO grid, SCE's Grid Demand cannot be simply measured by meters.

- SCE's load is measured in a "bottoms up" manner based on end-use retail meters.
- Like some munis, SCE has generation located downstream of the ISO interface which reduces the flows that SCE places on the ISO grid: not captured by bottoms up metering.
- Distribution-located generation is about 6-7% of total load for SCE.

The CRS and ETS billing determinants for SCE's load should be based on ISO Grid Demand and ISO Grid Energy, respectively.

- Total bottoms-up SCE SC load less 6-7%.
- Evaluate adjustment factor periodically.

Key Aspects of Mohave Generation Plant and the Eldorado Transmission System

The Mohave generation plant consists of two 790 MW coal units located near CA/Nevada border.

- 56% owned by SCE, remainder owned by Nevada Power, Salt River Project, and LADWP
- Non-SCE portion of Mohave serves load in other control areas.
- Since the non-SCE portion of Mohave is "dynamically dispatched" to these other control areas, it is not the load responsibility of the ISO under WECC rules.
- Non-SCE Mohave energy is delivered over transmission lines owned by Nevada, SRP, and LADWP, those portions are not part of the ISO Controlled Grid.

Preferred Resolution of Mohave Issue: Define Export

The term "Export", although used extensively in the ISO Tariff, is not defined.

SCE proposes the following definition:

> Export: The use of the ISO Controlled Grid for the transmission of Energy to serve a Load located outside the transmission and distribution system of a Participating TO.

Since the non-SCE shares of the Eldorado System are not part of the ISO Controlled Grid, the adoption of this Export definition would appropriately resolve SCE's Mohave issue. Additionally, it would resolve other issues such as whether the GMC should be applied to SDG&E's Southwest Power Link and COTP exports.

Alternative Resolution of Mohave Issue: Rate Reduction

- In the event that Non-SCE Mohave energy is determined to be an "Export", there should be a significant GMC rate reduction reflecting the limited impact Mohave energy has on the ISO's administrative costs.
- Non-SCE Mohave energy should pay 10% of the CRS charge and 10% of the ETS charge.
- The ISO performs much less service for this load since it is the load responsibility of other control areas, and it uses transmission capacity that is not part of the ISO Controlled Grid.

APPENDIX 7

IDENTIFICATION OF POTENTIALLY UNSTABLE BILLING DETERMINANTS AND THE POTENTIAL FOR ISO COST UNDER-RECOVERY

Certain billing determinants are less predictable and more volatile than others. For example, in the ISO's current GMC structure, the billing determinant for Control Area Services has varied from the budgeted amount by up to 6% per month (during 2002/2003). For the ASREO service category, the billing determinant was as much as 70% above, and 40% below budget in various months in 2001. This volatility could make it difficult to ensure the ISO has sufficient GMC collections to meet its ongoing funding requirements.

For the ISO's proposal:
Energy & Transmission Services (ETS): Net uninstructed deviations in MWh. Uninstructed deviations should already be discouraged in Phase IB of MD02 with penalties. Assessing GMC on these could be seen as another form of penalty that might further reduce these volumes. While this is good for grid operations, when volumes for a service category go down, the rates have to go up to recover the same costs. However only a small portion of the ISO's overall revenue requirement, 3%, is associated with this service category, and this mitigates the potential under-recovery risk associated with this service.

Forward scheduling service: The total volume in this billing determinant for the 2001/2002 period includes about 50% inter-SC trade schedules, which to date, have not been assessed GMC. These trades could be reduced in volume due to the new charge.

For MID's proposal
Resolving Energy Imbalances (REI): billing determinant of net uninstructed deviations (based on both demand (MW) and energy (MWh), with two tiers in each. The first tier would be a relatively low rate, while the second tier rate would be much higher for greater deviations, as much as 20 times the first tier rate). As a result of these potentially costly assessments on such deviations, particularly those falling in the second tier, the volumes in 2004 could be significantly below those used to set the rates, resulting in a significant under-recovery. This could create a revenue instability problem.

For SCE's proposal
Real Time Operation Services (RTOS): billing determinant of uninstructed imbalance energy in MWh. Uninstructed deviations should already be discouraged in Phase IB of MD02 with penalties. Assessing GMC on these could be seen as another form of penalty that might further reduce these volumes.

Offsetting the risk of these potentially unstable billing determinants are:

1. The ISO's ability to adjust rates to reflect revised and updated expectations for volumes during the year. The ISO currently has the ability to change rates on a quarterly basis if annual volumes are expected to deviate by more than 5% from the estimate used to set the rate. This, or a similar mechanism would be essential to ensure full recovery of costs by the ISO.

2. The ISO's Financial Operating Reserve, or cushion of funds, above what is needed for day-to-day cash needs. The ISO Tariff provides the mechanism for the ISO to establish a reserve fund of up to 15% of the Operating & Maintenance Budget, or about $26 million, that can provide some funding for costs in the event of a revenue shortfall in certain months. This funding is limited however, and would not provide adequate cushion for severe shortfalls. The ISO had anticipated relying on line of credit as an additional back-up when it established an unbundled GMC structure in 2001, such access to such credit facilities was eliminated as a result of the 2001 energy crisis and the loss of the ISO's creditworthy rating.

3. An alternative approach to the billing determinant volatility problem is to not set rates in advance, but to recover the monthly costs for a particular service over the actual billing determinant volumes in a given month, resulting in "floating rates". This approach is used at PJM and other ISOs, but was established as a result of a Settlement agreement with their ratepayers. Certain California GMC ratepayers have expressed opposition to this approach, and it is unlikely that the ISO successfully prevail over such opposition in a Section 205 filing at FERC.

APPENDIX 8

COMMENTARY ON PROJECT CHARTER OBJECTIVES/GOALS

The project charter set forth several goals for the project and the resulting new GMC rate structure. Comments regarding the proposals are provided with respect to these objectives.

- **Develop a rate structure that meets the FERC "just and reasonable" standard, and appropriately allocates ISO costs among the ISO's users.**

  Comments:
  Proponents of each proposal attempted to be mindful of any clear prohibitions made by FERC on rate structure or design issues.

  Each of the proposals have different views as to how ISO costs should be appropriately allocated to the ISO's users. For example, the ISO proposal would assess some GMC costs to Load in the ISO Control Area that does not use the ISO Controlled Grid (often referred to as "behind-the-meter load", while MID's proposal would not. SCE's proposal would assess GMC to municipal behind the meter load, but not to QF behind the meter load.

  Another example of differences in views of this issue is illustrated by a component of SCE's proposal which would provide for a reduced GMC cost for dynamically dispatched exports (i.e. this would benefit for schedules from its Mohave facility to co-owned facilities located in an adjacent control area.) The ISO or MID proposals would not provide a reduced GMC for this circumstance.

- **Develop a rate structure based on the principle of cost causation, which charges customers for the cost of services that they use/cause.**

  Comments:
  All of the proposals provide for some degree of "unbundling" of the GMC, where the objective is that users are charged for the services they are deemed to use. The proponents have arrived at different conclusions as to the ISO services, who uses such services, and how the users should be assessed.

- **Design a rate structure that is easy to administer (including reasonably cost effective, and benefits of change should outweigh the costs) and be understandable.**

  Comments:
  "Easy to administer" is a difficult goal. Easiest to administer would be a fully bundled GMC charge. All three proposals are more complex than the current GMC structure (as they contain more service categories and/or billing determinants).

The charges under all three of the GMC proposals would be set and published in advance which should facilitate understanding of the ISO cost recovery process.

- **Develop a rate structure that does not result in unmanageable adverse operational impacts.**

Comments:

Representatives from the ISO's various operations departments have participated in the development of the ISO's 2004 GMC structure proposal, and had no adverse comments about the ISO's proposal from this standpoint (and they support the ISO proposal.)

The ISO Grid Operations Department did note that the existence of a lower GMC charge for dynamic dispatch, as provided for in the SCE proposal, could marginally encourage the export of additional energy from the California ISO Control Area and the State of California in certain circumstances. While the DDES charge in the SCE proposal is to be applicable only for the SCE Mohave line for certain exports, the ISO believes that other parties could potentially argue that the reduced rate should be applicable to their unique situations as well, and thereby expand the applicability of the reduced exports charge to a larger volume of exports.

The ISO's Department of Market Analysis (DMA) also provided comments on the ISO's proposal, and noted no issues of significant concern. DMA also assessed the MID proposal and SCE proposals, and like the ISO proposal, reported no adverse findings from a market perspective.

- **Develop a rate structure that is arrived at through an open and balanced stakeholder process.**

Comments:

The ISO proposal was initially prepared by ISO staff to fulfill the directives of the 2001 GMC Initial Decision and to correct ISO perceived problems with the current GMC approach. The proposal was modified numerous times throughout the stakeholder process to incorporate stakeholders' concerns.

The MID proposal was initially prepared during 2001 and presented in the 2001 GMC rate case as an alternative to the ISO's three-bucket category structure. The ALJ in that case did not accept the MID proposal as a replacement of the ISO proposed structure, but directed the ISO to assist MID to fully develop its proposal. The ISO provided data to MID, and MID revised its proposal several times as a result of its continued assessments as to an appropriate GMC structure for the ISO, changes made to the ISO's proposal, and feedback from other stakeholders.

The SCE proposal was developed during the current stakeholder process, and initially presented during February 2003. The proposal has remained largely unchanged.

- **Recover approved ISO costs in a stable, low risk manner without excess volatility.**

Comments:

With the move to a new rate structure, there is increased risk that parties will modify behavior to reduce their charges under the new structure. Some billing determinants are more susceptible to this risk than others. Service categories of each GMC structure that are to some extent based on billing determinants that may be more volatile due to an SC's ability to change behavior to avoid charges include:

California ISO	Modesto Irrigation District	Southern California Edison
Energy & Transmission Services: Billing Determinant: Net uninstructed deviations. Impact: Parties could choose to deviate less (operationally this is good) Portion of GMC revenue requirement subject to this potentially volatile billing determinant: **3%** (3% of the 16% of the ETS category) Forward Scheduling: Billing Determinant: number of schedules submitted (load, generation, export, import, inter-SC trades) Impact: SCs may have some ability to reduce the number of schedules they submit- particularly inter-SC trades, and to a lesser extent load schedules. Portion of GMC subject to this potentially volatile billing determinant: **8%**	Resolving Energy Imbalances (REI): Billing Determinant: Uninstructed deviation energy and demand. Impact: Same as ISO's "ETS" to left. Portion of GMC revenue requirement subject to this potentially volatile billing determinant: **18%**	Real Time Operation Services (RTOS or RMOS): Billing Determinant: MWh of uninstructed real time energy. Impact: Same as ISO's "ETS" to left. Portion of GMC revenue requirement subject to this potentially volatile billing determinant: **7.1%**

The ISO's current GMC structure provides for the possibility of quarterly changes in GMC rates if the volumes on which the charges are calculated are forecast to change by more than 5% for the year. Similar provisions would be necessary under any new GMC structure, and should be sufficient to address the concern of potentially more volatility in any of the three proposals.

It should also be noted that "Market" related category of all three proposals is also based on a relatively volatile billing determinant, but this is also the case with *the current GMC structure's "Ancillary Services and Real Time Energy Operations" category.*

- **Have the new rate structure filed with FERC by November 1, 2003, so that it can be effective January 1, 2004.**

  Comments:
  The timeline for this project will permit the approved rate structure to be filed on a timely basis.

- **Meet the terms of the 2002 GMC Settlement Agreement, which set forth issues to be covered in this 2004 GMC Stakeholder Process.**

  Comments:
  The 2002 GMC Settlement agreement, filed with FERC in November 2002, settled the issues in the 2002 GMC rate case, and also set forth parameters for this 2004 GMC Rate Structure stakeholder process. The ISO has performed an assessment of the conduct of this stakeholder process against those commitments, and believes the terms have been fulfilled.

GMC PROPOSAL

Southern California Edison

July 17, 2003

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The CRS and ETS billing determinants for SCE's load should be based on ISO Grid Demand and ISO Grid Energy, respectively.

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- Evaluate adjustment factor periodically.

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- The ISO performs much less service for this load since it is the load responsibility of other control areas, and it uses transmission capacity that is not part of the ISO Controlled Grid.

CALIFORNIA ISO

California Independent
System Operator

ISO Rate Proposal For 2004

Ben Arikawa
Senior Financial Analyst

ISO Finance Committee
July 17, 2003

Topics

- Objectives
- Steps
- Results
- Benefits of ISO Proposal
- Conclusion

Objectives

- Meet Project Charter criteria
- Design rates to better address drivers of ISO costs
- Avoid bias and deal-making in development of rates

Steps

- Defining/Designing Services
- Assigning Costs
- Developing Method of Cost Recovery
- Mitigation of Bill Impacts

Results

- *Operating the Grid* – **Grid Reliability Services**
  - Core Reliability
  - Energy and Transmission
- *Creating and Operating Markets* – **Market Services**
  - Forward Scheduling
  - Congestion Management
  - Market Usage
- *Serving Customers* – **Settlements, Metering and Client Relations**

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Grid Reliability Services

Core Reliability

- Core activities of the ISO as the Control Area operator
- Billing determinant
  - Metered non-coincident peak demand (MW-months)
- Why?
  - Benefits all entities within control area
  - Captures costs of the ISO's around the clock operation
  - Demand based charge responsive to participants request (CPUC and EOB)

Grid Reliability Services
Energy and Transmission

- Operating the Grid to ensure the ISO's ability to manage flows and meet contingencies
- Billing determinants
  - Load and exports (MWh)
  - Net uninstructed deviations (MWh)
- Why?
  - Benefits entities drawing power from the ISO Grid
  - Captures costs of ISO monitoring and maintaining the Grid
  - Recognizes a contribution of MID (net uninstructed deviations)

Market Services

Forward Scheduling

- **Processing energy schedules and awarded Ancillary Services bids**
- **Billing determinant**
  - Count of number of final Hour-Ahead schedules processed
    - Load, generation
    - Import, export
    - Inter-SC trade
    - Awarded Ancillary Services (market and self-provided)
- **Why?**
  - Benefits entities that schedule across ISO Control Area
  - Charges entities for ISO scheduling costs not previously assessed
  - Reflects the role of the ISO as coordinator of scheduling requirements across the Grid

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Market Services
Congestion Management

- Monitoring and managing interzonal flows
- Billing determinant
  - Net scheduled Hour-Ahead interzonal flows (MWh)
- Why?
  - Benefits entities in Controlled Grid that have transmission or schedule across zones
  - Reflects the role of ISO as coordinator of flows across the Grid
  - Responsive to participant requests for retention on an interim basis (CPUC, EMS)

Market Services

Market Usage

- Creating, operating and maintaining markets
- Billing determinant
  - Purchases and sales of Ancillary Services, Instructed Energy and net uninstructed deviations (MWh)
- Why?
  - Provides benefits to those entities that use ISO markets
  - Reflects the role of ISO as the central clearinghouse of trades
  - Netting deviations reflects comments of market participants

Settlements, Metering and Client Relations

- Metering, billing, customer training and resolving disputes
- Billing determinant
  - Monthly fee per customer
  - Mitigation of bill impact - Association of costs with related services
- Why?
  - Provides benefits to entities by making data, training and dispute resolution accessible
  - Captures costs of serving ISO customers

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Rates

Designing Services	Grid Reliability			Market Services			Settlements Metering Client Relations
	Core	ETS Load	ETS Deviations	FS	Cong	MU	
Assigning Costs (millions)	$93.5 (39%)	$30.7 (13%)	$7.7 (3%)	$19.0 (8%)	$10.0 (4%)	$28.8 (12%)	$47.9 (20%)
Billing Determinants	534,032 MW mos.	239.9 million MWh	16.4 million MWh	12.3 million schedules	87.9 million MWh	45.7 million MWh	1,562 customer months
Preliminary Rates	$175	$0.13	$0.47	$1.55	$0.11	$0.63	$500
Mitigation		$0.11	$0.40		$0.05	$0.22	
Resulting Rate	$175 per MW-mo	$0.24 per MWh	$0.87 per MWh	$1.55 per final HA schedule	$0.16 per MWh	$0.85 per MWh	$500

Figures are shown only for illustrative purposes. Actual costs, cost assignments and rates for 2004 will be the result of further analysis using 2004 Budget data.

Benefits of ISO Proposal

- Rate design consistent with cost causation
- Can be implemented within Settlements System
- Minimal impact on grid operations
- Recovers revenue requirement in stable manner
- Vetted through a balanced and open stakeholder process
- Avoids bias towards any entity or group of entities

Other Methods

- Exempt Me!
- Create categories of ‘defined’ exemptions
- Bill at the lowest time of the day
- Bill only other people’s activities

Conclusion

Recommend adoption of ISO Proposal:

- Meets objectives of Project Charter
- Justifiable evolution & improvement upon current GMC structure
- Responsive to issues from 2001 Initial Decision, Commission Order and 2002 GMC Settlement

California Department of Water Resources
State Water Project
Position Paper

on

The Independent System Operator
2004 Grid Management Charge Rate Structure Proposal

July 16, 2003

INTRODUCTION

The California Department of Water Resources, State Water Project (CDWR/SWP), presents this latest position paper on the 2004 GMC Rate Structure Project for the consideration of the ISO and other participating parties. The CDWR/SWP has previously commented on various aspects of the GMC structure in its written submittals of August 8, 2002, December 31, 2002, February 13, 2003, and February 19, 2003, and appreciates the opportunity to provide further comments at this time. This present memorandum is designed to summarize the CDWR/SWP's overall position on the GMC proposals advanced by the ISO, Southern California Edison Company ("SCE") and Modesto Irrigation District ("MID"), as those proposals have evolved to date. For the reasons explained below, CDWR/SWP strongly recommends that the ISO apply a 12-month coincident peak billing determinant for the Core Reliability Services category.

ISO PROPOSAL

CDWR/SWP continues to have two major concerns regarding the Core Reliability Services ("CRS") category of the ISO proposal. First, the costs allocated to this category are high. As discussed below, CDWR/SWP recommends that the costs associated with some of the activities under CRS should be re-allocated to Energy and Transmission Services ("ETS"). Second, the ISO's proposed use of a gross non-coincident peak ("NCP") demand billing determinant for CRS is counter-productive to cost causation and grid efficiency goals, and is contrary to FERC policy. If the ISO uses a demand-based allocation for the CRS category, CDWR/SWP believes it would be more appropriate to base this charge on each customer's contribution to ISO system monthly peak demand ("12-CP"). Alternatively, the ISO could continue to use a volumetric approach and base its CRS charge on each customer's share of Control Area Gross Load, as historically proposed by the ISO and recently endorsed by the Commission. Either of these approaches would reflect cost causation far better and would be more fair than a non-coincident peak methodology.

ALLOCATION OF CRS COSTS

The ISO's proposal allocates $93.5 Million to the CRS category, which is approximately 39% of the ISO's total revenue requirement of $237.6 Million for the GMC (ISO White Paper, June 25, 2003, Table 2).

The CRS category includes the following activities (ISO White Paper, June 25, 2003pp. 3-4):

- Monitoring of system conditions and dispatching to maintain reliability
- Coordination, communication, and integration with neighboring Control Areas
- Intertie scheduling
- Compliance with reliability standards
- Transmission and generation outage coordination
- Management, monitoring and approval of new generator interconnections

- Evaluation of transmission expansion
- Performance of operational studies, system security analyses and system planning studies to ensure overall reliability

In addition to the $93.5 million allocated to CRS, the ISO has allocated $38.3 million to ETS for a cumulative total of $131.8 million for Grid Reliability Services. This means the CRS category constitutes 71% of these costs, while the ETS portion is only 29%. Therefore, the ETS category represents less than 1/3 the amount allocated to Grid Reliability Services. The CRS category should only include costs associated with four principal grid functions: Grid Planning, Regional coordination, Security coordination, and Coordination operations. Three of the bullet items above, "Monitoring of System Conditions and Dispatching," "Transmission and Generation Outage Coordination," and "Management, Monitoring and Approval of New Generator Interconnections" should be assigned to the ETS category to more properly reflect the imposition of costs on the ISO system.

PROPOSED 12-NCP BILLING DETERMINANT FOR CRS

The CDWR/SWP has consistently expressed its disagreement regarding the assessment of CRS charges on the basis of each SC's non-coincident peak demand (see CDWR/SWP's December 31, 2002 Memorandum, p. 2). It is a well-established principle in utility ratemaking that, with rare exceptions applicable only for certain utilities with unique factual circumstances, non-coincident demand is not generally relevant for cost allocation or billing determinant purposes because the core costs incurred by a transmission grid operator, including the ISO, depend on the maximum *system* load which the grid must serve at any moment in time, rather than non-coincident demand. The ISO has not established that the unrelated individual peak demands experienced by different customers on different days of each month bears a meaningful relationship to the ISO's CRS costs.

CDWR/SWP's view is supported by recent FERC developments. The FERC reiterated in Order No. 888 that "We are reaffirming the use of a twelve monthly coincident peak (12-CP) allocation method because we believe the majority of utilities plan their systems to meet their twelve monthly peaks. Utilities that plan their systems to meet an annual system peak…are free to file another method *if* they demonstrate that it reflects their transmission system planning." Order No. 888, FERC Stats. & Regs. ¶ 31,063 at 31,736 (slip op. at 296-296). Notably, the concept of a non-coincident peak is not recognized in Order No. 888, even as an exception. The coincident peak method is reflected in approved utility tariffs on file with the Commission, such as the Midwest ISO's approved Open Access Tariff, sec. 34.2, which provides that "…the Network Customer's monthly Network Load will be its hourly load *coincident with the monthly peak of the Transmission Owner….*" The ISO's most recent reliability assessment confirms that the ISO's planning is based on a coincident peak demand, not on some other method. The 2002 Final Report prepared by the ISO's Grid Planning Department is based on the fundamental premise that "Loads modeled in power flow cases representing peak summer load conditions will represent a maximum anticipated *coincident* peak for the Cal-ISO Control Area…." (2002 California ISO Controlled Grid Study Report, February 21, 2003).

The non-coincident peak idea is also contrary to the Commission's most recent decision on GMC structure. In Opinion No. 463, issued May 2, 2003 in Docket No. ER01-313, FERC strongly endorsed the concept of basing the CAS charge on Control Area Gross Load and applying a volumetric billing determinant, as proposed by the ISO in the 2001 (and 2002) GMC rate case. In assessing the CAS charge on Control Area Gross Load, each customer's load is effectively allocated a share of the costs based on the customer's contribution to overall *system* load, which is more closely analogous to a 12-CP method than to a non-coincident peak approach. (Opinion 463 also directed that certain customers with behind-the-meter generators should be allocated CAS costs based on their highest monthly demand, for the purpose of *reducing* the share of costs allocated to them, a situation far different from and unrelated to the notion of basing the entire charge to all customers on the separate customer peaks).

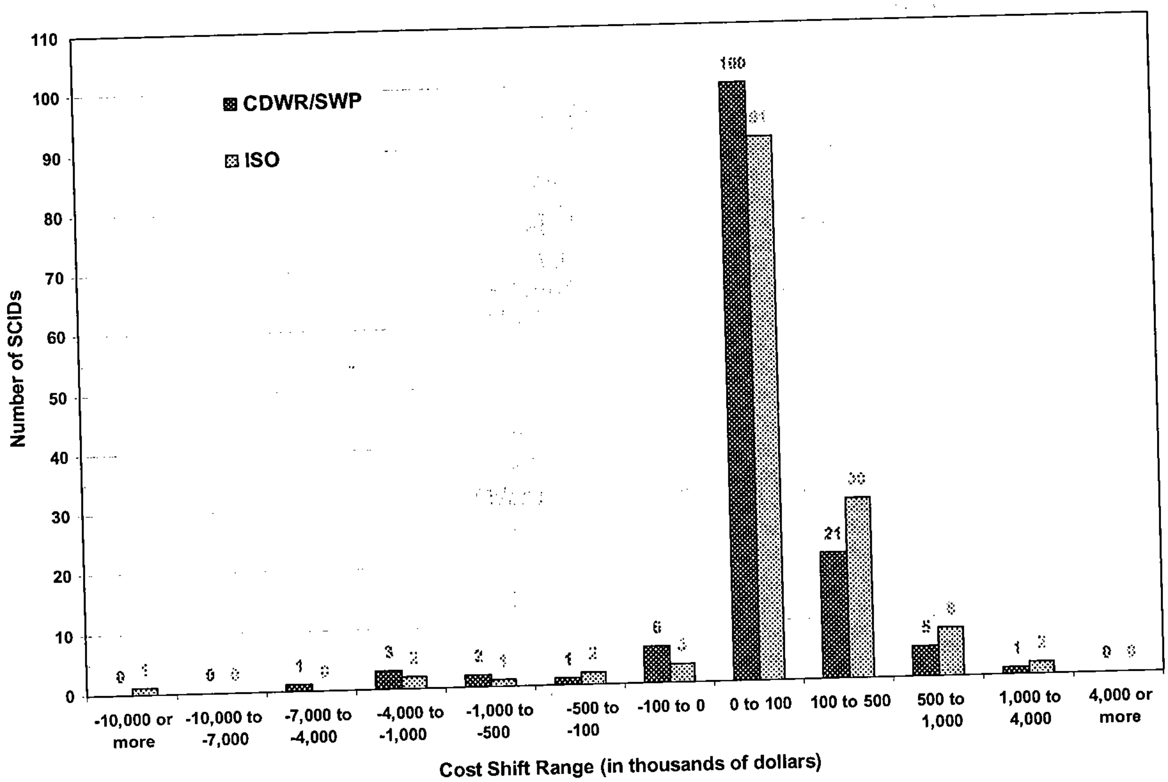
A coincident peak methodology advances key objectives for grid use and furthers cost causation principles. The 12-CP method creates desirable market signals to encourage the use of the grid during non–peak time. Benefits to using the grid during non-peak periods include reducing grid congestion, and reducing demand spikes. Both of these benefits reduce the overall costs of operating the grid and allow the ISO to more efficiently manage the grid. Alternatively, CDWR/SWP supports the use of a volumetric billing determinant based on Control Area Gross Load as an accepted and reasonably cost-based method for assigning costs and charging for the ISO's core functions. This method was advanced by the ISO in the 2001 and 2002 GMC cases, and was strongly endorsed by the FERC in Opinion No. 463.

In contrast, the use of a non-coincident peak method departs from cost causation and results in discrimination by assigning costs to certain customers with large off-peak loads like the CDWR/SWP in a manner which is not related to the costs imposed on the overall system by such customers. This effectively discourages efficient use of the grid by customers that are able and willing to shift their load to off-peak periods to assist in grid operations. In sum, the use of a non-coincident peak method results in veritable "*anti-time-of-use*" rates.

The ISO analyzed the GMC rate structure proposals (ISO 12-NCP, CDWR/SWP 12-CP, MID, and SCE) to determine the billing impact for each SCID and presented the results to the GMC Working Group on June 4, 2003. The ISO and CDWR/SWP proposals differ *only* in the methodology used to allocate the revenue requirement for the CRS Function of the GMC. Charts used in the June 4th presentation and those prepared by CDWR/SWP are referenced in the following.

Two charts developed by the ISO, entitled "Distribution of Bill Impacts: ISO 12-NCP Proposal" and "Distribution of Bill Impacts: DWR 12-CP Proposal," are combined in the figure below to compare the financial impact of the 12-NCP and 12-CP methodologies. This figure shows the 12-CP methodology decreases the number of SCIDs that are negatively impacted by reducing the cost shifts to the SCIDs.

Cost Shifts from the Current ISO GMC Rate Structure



To summarize, it is CDWR/SWP's view that the ISO has not presented adequate rationale for departing from the established standard utility rate-making concept endorsed by FERC, or allocating costs contrary to its own underlying grid planning assumptions, by basing such a large cost category on non-coincident peak demands. The CDWR/SWP continues to believe that there exists no plausible cost-based reason for assessing the CRS charge on the basis of a customer's non-coincident peak demand. Because the CRS costs are such a significant portion of the GMC total revenue requirements (39%), the CDWR/SWP is unable to support the ISO's 2004 GMC Rate Structure Proposal unless the billing determinant for the CRS category either includes a 12-CP component or is based on a volumetric method..

SCE PROPOSAL

As discussed in the CDWR/SWP February 19 comments, SCE's proposal generally represents an improvement over the prior 3-category GMC by providing greater granularity in the ISO's functions and resultant billing categories. SCE recognizes that Control Area Services should be allocated costs separately from Scheduling, Market Operations, and Real-Time Operations.

However, SCE's proposal for a Dynamic Dispatch Scheduling Service suffers from several major flaws. First, it lacks clarity as to how the charge would apply; second, it is not cost-based, and third, as presently envisioned, it may be discriminatory.

As an initial observation, it is not entirely clear whether any charge would be assessed on energy which is not dynamically dispatched. In particular, if DDES would apply only to Mojave export energy, it is unclear whether under SCE's proposal the full CAS charge would continue to apply the 56% which is served by the ISO grid.

SCE proposes that DDES be assigned 10% of the otherwise applicable CAS costs/charges. However, neither SCE nor the ISO has done a reliable analysis of the extent to which DDES contributes to the CAS costs. The 10% cost allocation proposal appears arbitrary since SCE's own brief review of ISO budget information suggests that up to 25% of the CAS costs may be identified with ISO activities which DDES relies on. There is simply no basis for charging DDES only 10% of the otherwise applicable charge. .

In addition, it appears that the DDES charge might be applied in a discriminatory fashion. In response to an inquiry from SWP during the April 2 conference call, the ISO stated that the DDES service charge would not be available for any future potential dynamically dispatched generation.

MID PROPOSAL

MID's June 4th proposal eliminates the Forward Scheduling Function contained in its prior proposal, and offers two options for measuring customers' use of the Managing Transmission Flows Function. The first option (Option A) recovers costs for this function by reinstating the 12 NCP demand charge eliminated in the May 12th proposal and applying it in conjunction with an energy charge. The second option (Option B) is similar to the May 12th proposal which eliminated the 12 NCP demand charge from the March 11th proposal and recovers costs through energy charges. CDWR/SWP has previously commented that MID oversimplifies the incurrence of costs by the grid by assuming that there are but a few basic functions of the grid. The MID proposal fails to acknowledge the many activities associated with long-term transmission planning, design, maintenance, and growth, or the various activities currently reflected in the CAS and proposed for the CRS upon which *all* customers, including MID, necessarily depend.

Further, MID's proposal for the Resolving Energy Imbalances category demand charge would be based on the customer's annual, non-coincident system peak, with the demand charge for Managing Transmission flows based on a 12-month non-coincident peak. As with the ISO's proposal, there is no cost basis for this discriminatory approach, and it would discourage use of the grid at off-peak times by those able and willing to shift load, like CDWR/SWP.

Finance Committee

California Independent System Operator

Finance Committee Meeting

July 17, 2003

Grid Management Charge Rate Structure Proposal

California Department of Water Resources

State Water Project

Introduction

CDWR/SWP agrees with the goal of the ISO to honor and incorporate cost causality into the Grid Management Charge.

This presentation includes:

1. The 2004 GMC rate structure proposed by CDWR/SWP,
2. Descriptions of non-coincidental and coincidental peak methodologies,
3. Charts illustrating the CDWR/SWP and ISO rate proposals, and
4. A brief comparison of the cost shifts produced by the CDWR/SWP and ISO rate proposals.

1. 2004 CDWR/SWP GMC Rate Proposal

CDWR/SWP proposes a rate structure that:

- With the exception of the Core Reliability Services Function, the SWP proposal incorporates the same rate structure that the ISO proposes in its design, and
- Utilizes a coincidental peak methodology for the Core Reliability Services Function billing determinant.

2. Discussion of Non-Coincidental and Coincidental Peak Methodologies

A non-coincidental peak methodology:

- Sums two or more peak loads that do not occur in the same time interval (hour),
- Does not provide market signals for shifting use of the grid to off-peak periods,
- Discriminates against customers that use the off-peak period by assigning costs which are not related to their effect on the system, and
- Is used to allocate costs associated with building transmission systems.

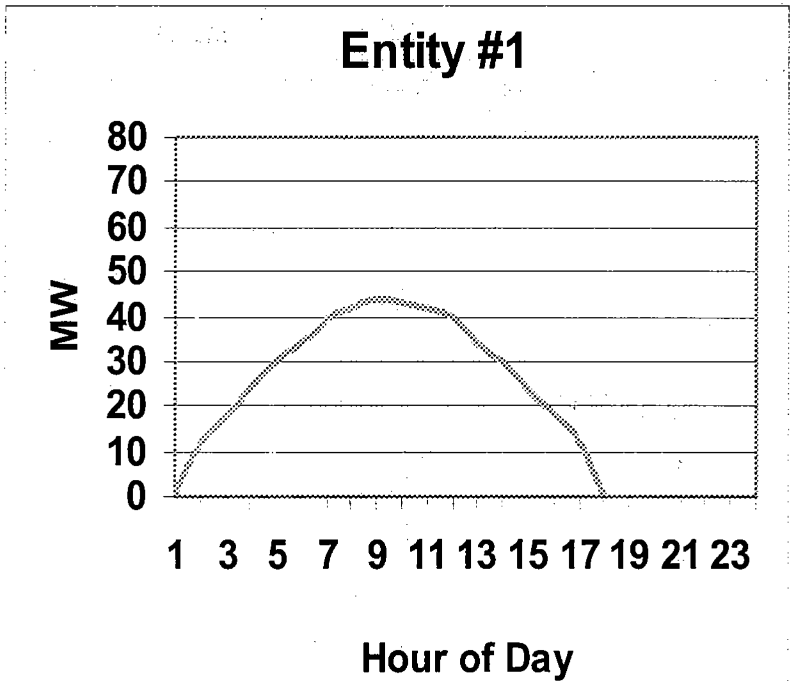
2. Discussion of Non-Coincidental and Coincidental Peak Methodologies (continued)

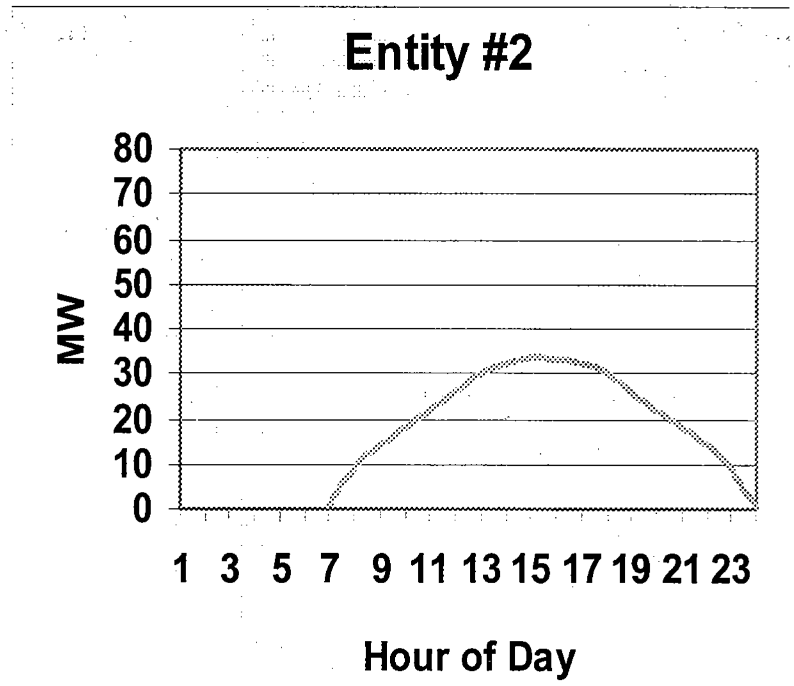
A coincidental peak methodology:

- Sums two or more peak loads that occur in the same time interval (hour),
- Provides desirable market signals that encourage shifting use of the grid to off-peak periods,
- Reduces the costs of operating the grid by allowing more efficient management of the grid, and
- Is more closely related to the volumetric billing determinant strongly endorsed by FERC Order 888, and proposed by the ISO in the 2002 GMC rate case.

3. Simple Representation of Non-Coincidental and Coincidental Peak Methodologies

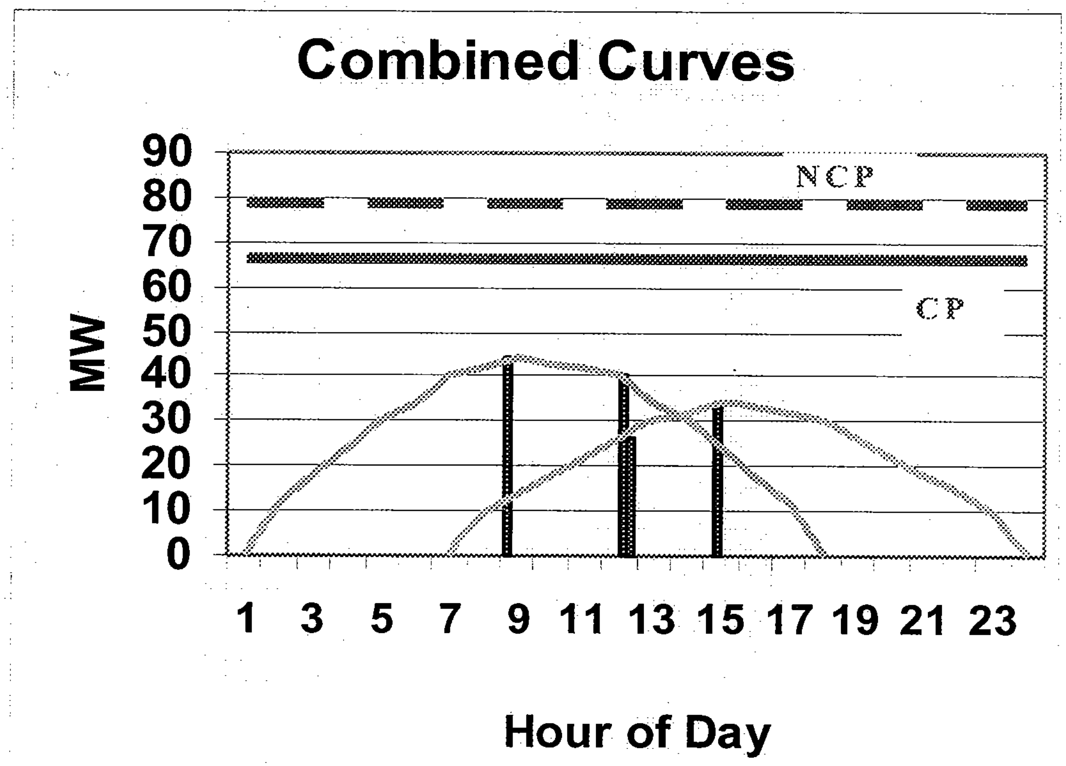
These two charts represent simple demand curves for two entities that combine to make an ISO.





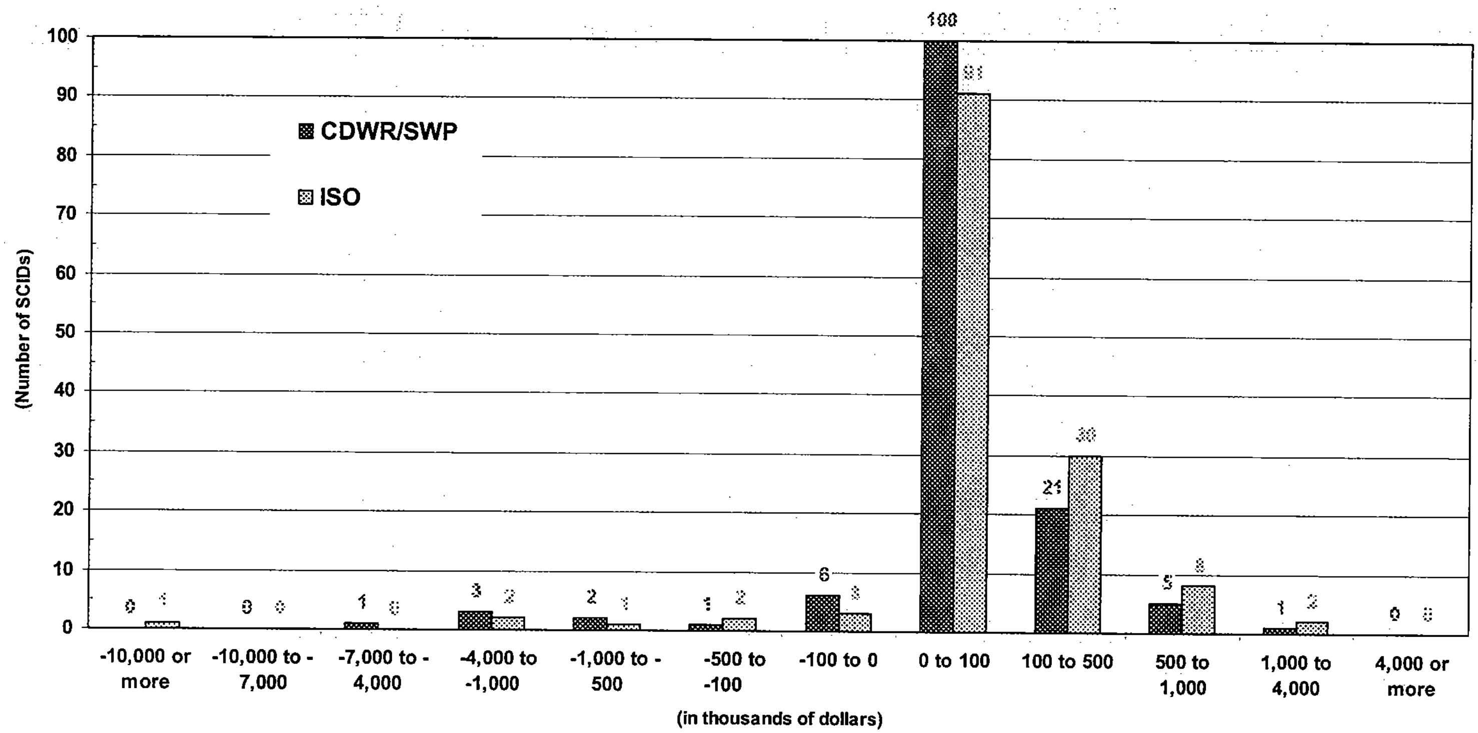
3. Simple Representation of Non-Coincidental and Coincidental Peak Methodologies (cont.)

The sum of the peaks and the coincidental peak are shown in the combined chart below.



4. Comparison of Rate Proposals

The chart below groups the scheduling coordinators by the magnitude of the cost shift produced from the CDWR/SWP and ISO proposals.



4. Comparison of Rate Proposals (continued)

Cost shifts to the customer class categories, defined by the CPUC, are shown below.

Proposal	CPUC Category		
	Investor Owned Utility	Governmental Entity/Municipal	Other
Current GMC	$ -	$ -	$ -
ISO Proposal	$ (13,936,035)	$ 1,321,352	$ 12,532,683
ISO Proposal with 10% GRS rate for Mohave	$ (14,357,723)	$ 1,506,963	$ 12,768,759
ISO Proposal with 25% GRS rate for Mohave	$ (14,286,799)	$ 1,475,745	$ 12,729,054
CDWR Proposal - 12 CP	$ (3,174,924)	$ (3,353,000)	$ 6,445,924
MID Option A	$ (24,891,846)	$ 5,543,007	$ 19,266,840
MID Option B	$ (17,752,530)	$ 3,478,363	$ 14,192,168
SCE 10% DDES	$ 3,496,347	$ 2,069,370	$ (5,565,717)
SCE 25% DDES	$ 3,610,125	$ 2,014,816	$ (5,624,941)

Summary

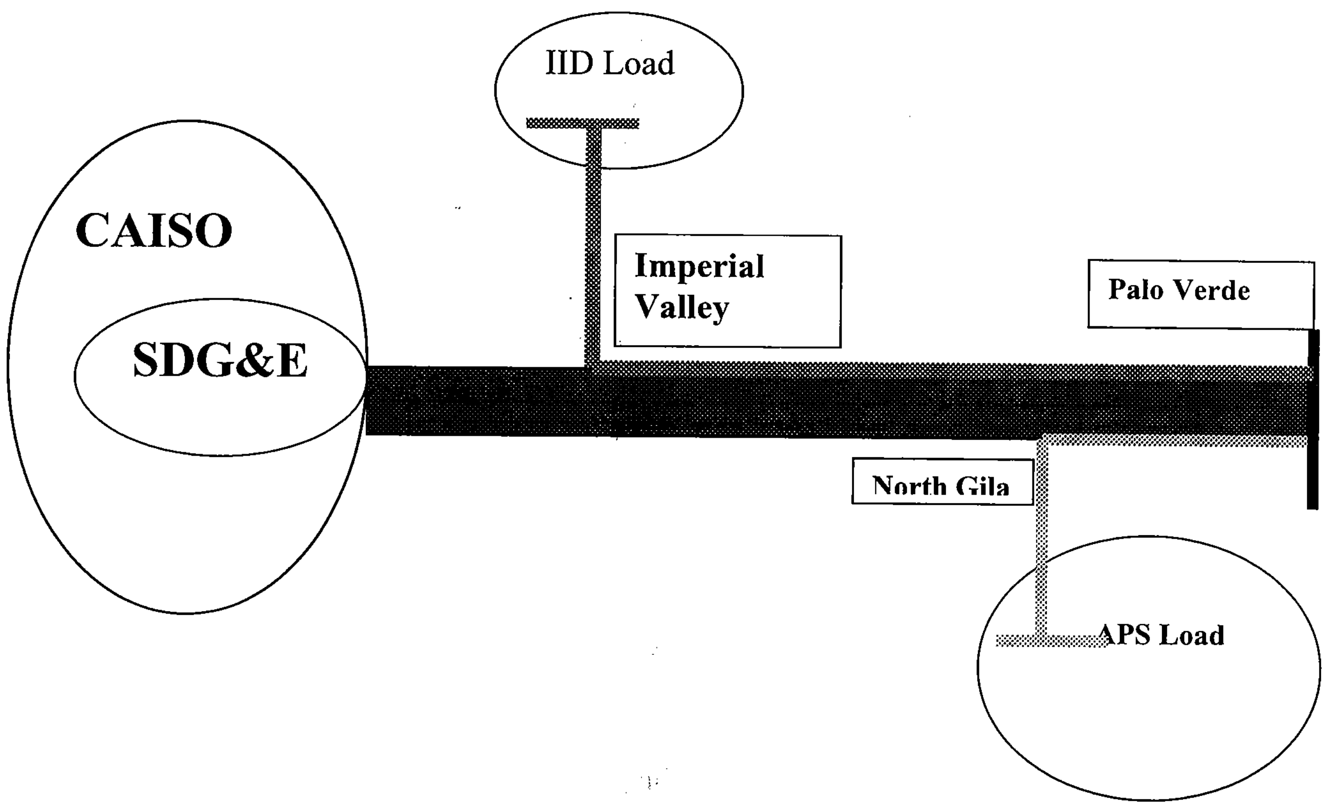
The CDWR/SWP proposal:

- Maintains a cost causality relationship for Core Reliability Service charges,
- Provides market signals to promote efficient use of the grid,
- Encourages off-peak use of the grid, and
- Results in less cost shifts from the current GMC design than the ISO proposal.

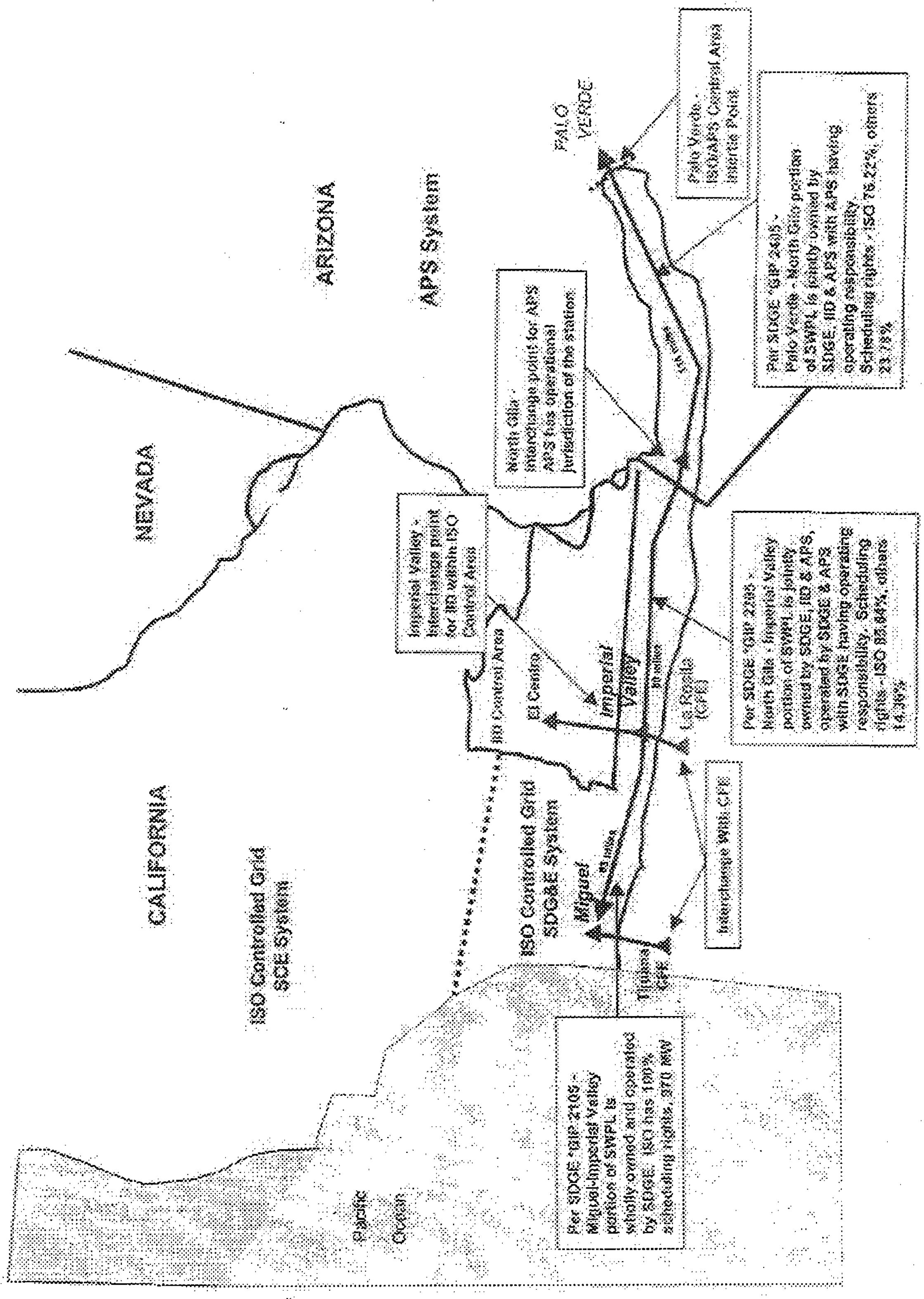
APS/IID SOUTHWEST POWERLINK SCHEDULES

- Limited to their respective SWPL ownership shares
- APS and IID Load *outside* ISO control area – ***not*** an ISO load responsibility.
- Each "export" has a corresponding import, for a zero net export (after compensation for losses).
- ISO *not* responsible for energy or capacity associated with such schedules – entirely the responsibility of APS and IID.
- ISO has no responsibility under MORC for such "exports."
- Reciprocity - ISO has rights in the APS control area – consistent with WECC practice, APS assesses ***no*** administrative charges on the ISO schedules.

EXHIBIT SDO-6
SWPL SYSTEM



SDO-3



*SDGE Grid Interconnection Procedure (GIP)

SWPL_Participation_2
jkk 9/21/01

2004 GMC Rate Structure Project Briefing

To: Participants in 2004 GMC Rate Structure Project

From: Ben T. Arikawa, Senior Financial Analyst

Date: July 21, 2003

Re: **2004 GMC Rate Structure Project related items**

This Briefing contains:

- New postings;
- Contact list;
- Availability of updated data;
- Brief notes to the July 17th Finance Committee meeting; and,
- Location of Agendas for July 24th Finance Committee and Board meetings.

New postings

The notes to the June 4th and 16th meetings were posted on the GMC main page: http://www.caiso.com/docs/2003/02/07/2003020716402314262.html . They had been posted to the public discussion board and I received no comments or edits to them.

Also, I posted comments received from CDWR, Mirant, CMUA, CPUC and the EOB to the public discussion board located at: http://www1.caiso.com/discus/messages/875/875.html. . These comments were in response to Phil Leiber's e-mail request of July 10, 2003.

Contact List

Attached with this Briefing is a contact list of participants in the conference calls and meetings of the GMC Project. I do not have complete contact information on each participant. I do believe that the information is a fairly complete representation of participation.

Availability of updated data

We have compiled updated billing determinants for the period September 2001 through February 2003 for all the proposals. The spreadsheet containing these data was distributed on Friday.

We have also updated the net uninstructed deviation data for the period September 2001 through February 2003. This data is available on request to those entities that have signed the Confidentiality Agreement and the Non-Disclosure Certificate. Please let me know if you would like a copy. As of Friday, July 18th, I received requests from Mirant, CAC/EPUC, MID, CDWR, and Navigant (David Cohen).

Brief notes to July 17th Finance Committee meeting

The Finance Committee met for about 5 hours yesterday, July 17th. Mr. Gage and Mr. Florio were in attendance. Mr. Kahn attended by phone. The meeting began with public comments. Rod Aoki (CAC/EPUC) spoke first, stating that CAC/EPUC were appreciative of the process, but that they preferred the MID or SCE proposal since both lacked an assessment on behind the meter standby load.

Kevin Smith, CMUA, also expressed appreciation for the way in which the stakeholder process had been conducted. However, CMUA was concerned that the ISO Board could not make a fully informed decision on the GMC rate design for 2004 in the short time that they would have to digest all the information. CMUA was also concerned about the size of the ISO Budget. Mr. Kahn did not agree with Mr. Smith's characterizations concerning either the ability of the Board to make an informed decision or that the ISO Budget was too large.

Karen Shea (CPUC) spoke in general support of the ISO proposal. This support was qualified by a concern over the effect the rate design would have on Distributed Generation. As to SCE's proposed Dynamic Dispatch Export Service for Mohave, the CPUC was concerned that it would set a dangerous precedent. Concerning SDG&E's proposal to exempt flows to APS and IID on SWPL, the CPUC had no opinion as the effects were not well understood. Ms. Shea suggested that it would be feasible to maintain the current GMC rate design especially if the ISO would be modifying its current rate design to conform with the FERC Order on the 2001 GMC. Finally, the CPUC expressed some concern about the MID proposal.

Brian Hitson (PG&E) expressed general support for the ISO proposal, but had some concern over the continued use of a gross metered demand. PG&E wanted the ISO to consider implementation of the behind the meter demand charge contemplated in the FERC Order. Finally, PG&E thought that the FERC Order's support for the ISO's pursuit of "Other Appropriate Parties" was a good thing, and wondered when the ISO planned to incorporate that into its rate design.

Phil Leiber gave a short introduction to the 2004 GMC Rate Structure Project, outlining the process that led up to the proposals.

Prior to the first presentation, Mr. Gage requested that each party address three specific topics: (1) what policies underlie the particular functionalization of the proposals, (2) what is the speaker's best sense of how the proposal comports with the FERC Order, and; (3) what issues might arise as the result of implementation of MD02.

The presentations given by the proponents are posted here: http://www.caiso.com/docs/2003/07/11/2003071116063926937.html. I will not summarize them, except to place them in order of appearance:

1. ISO
2. SCE
3. MID
4. SDG&E
5. CDWR

Additional public comment was received from Carrie Downey (IID), who commented that IID was present and listening to the discussion.

At this point, the Committee asked questions. Mr. Gage had some questions for Ms. Barkovich and Ms. Yap concerning the CDWR's contention that coincident peak was superior to non-coincident peak as a billing determinant for Core Reliability Services. There was also a question concerning the CPUC's issue of the impact on Distributed Generation.

At the end of the public session, Mr. Gage asked each proponent to provide to the Committee a discussion of the stability of revenue recovery under the assumption of declining market volumes and to provide a critique of the other proposals specifically addressing cost causation principles. These were to be provided to the Committee by noon, Tuesday, July 22nd. Please e-mail your responses to me at barikawa@caiso.com, or alternatively, to the entire GMC WG (gmcwg@caiso.com). They will be forwarded to the Board prior to next Thursday's Board meeting.

Location of Agendas for July 24th Finance Committee and Board meetings.

There will be a two-hour Finance Committee meeting scheduled for July 24th from 8:30 to 10:30.

The agendas for the July 24th Finance Committee and Board meetings can be accessed from this page:

http://www.caiso.com/meetings/index.cgi?showonly=BOARD.

If you have any questions about any of the information contained in this memorandum or about the process, please do not hesitate to contact:

Phil Leiber pleiber@caiso.com (916) 351-2168	Ben Arikawa barikawa@caiso.com (916) 608-5958

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Email Addresses 07-21-03.txt

From: lkirsch@svn.net
Sent: Monday, July 21, 2003 11:14 AM
To: Arikawa, Ben
Cc: Pritchard, Jan
Subject: Email Addresses

Ben:

Could you please send me the email addresses of the four ISO Governors (Florio, Gage, Guardino, and Kahn)? Thanks.

Laurence
****
Laurence D. Kirsch
Laurits R. Christensen Associates, Inc.
e-mail: LKIRSCH@LRCA.COM
voice: (415) 663-8608
fax: (415) 663-8818

Please visit our website at WWW.LRCA.COM
****

From: lkirsch@svn.net
Sent: Tuesday, July 22, 2003 10:57 AM
To: Arikawa, Ben
Cc: Pritchard, Jan; Neal, Sean
Subject: Memorandum to Finance Committee Chairman Gage

Ben:

On behalf of the Modesto Irrigation District, I have just sent the attached memorandum to Kim Hubner, asking her to forward the memorandum to Finance Committee Chairman Gage and the other Governors. I would like to ask you to please forward this memorandum to members of the stakeholder working group.
Thanks.

Laurence

****
Laurence D. Kirsch
Laurits R. Christensen Associates, Inc.
e-mail: LKIRSCH@LRCA.COM
voice: (415) 663-8608
fax: (415) 663-8818

Please visit our website at WWW.LRCA.COM
****

CALIFORNIA ISO

FINAL
Released: July 22, 2003

PUBLIC NOTICE OF ISO BOARD OF GOVERNORS AND COMMITTEES - MEETING SCHEDULE

The Board of Governors of the California Independent System Operator will meet:

Date:	**July 24, 2003**
Location:	Committee Meetings / Board of Governors Meeting: California ISO Offices 101 Blue Ravine Road Folsom, CA 95630
URL Address:	**Free Internet Audio Transmission of Board Meetings will be available.** **Please go to** http://www.caiso.com/pubinfo/BOG **for the URL address.**
Conference Call Information: ***(LISTEN ONLY)***	Dial-in Number: **(877) 381-5998** Passcode: **ISO Board** **Line available from 9:15 a.m. – 2:00 p.m.**

The following is a schedule of meetings for the ISO Board of Governors and Committees of the Board of Governors:

		LOCATION
8:30 a.m. - 10:30 a.m.	**Finance Committee** Executive Session – 8:30 – 9:15 General Session – 9:15 – 10:30	*Conference Room 101A – 1A & 1B*
10:30 a.m. – 11:30 a.m.	**Audit Committee** General Session	*Conference Room 101A – 1A & 1B*
11:30 a.m. – 5:00 p.m.	**Board of Governors** General Session - 11:30 – 2:00 Executive Session – 2:00 – 5:00	*Conference Room 101A – 1A & 1B*

151 Blue Ravine Road Folsom, California 95630 916 351-4400

CALIFORNIA ISO

California Independent
System Operator

Memorandum

To: ISO Finance Committee

From: William J. Regan, Jr., Chief Financial Officer
Deborah Le Vine, Director of Contracts
Philip Leiber, Treasurer & Director of Financial Planning
Ben Arikawa, Senior Financial Analyst

CC: Board of Governors
Board Assistant, ISO Officers

Date: July 18, 2003

Re: ***Grid Management Charge- 2004 Rate Structure***

This memorandum requires Board Action.

Since August 2002, ISO staff and stakeholders have participated in a comprehensive examination of alternatives for a new GMC rate structure for 2004. The results of this process were presented to the Finance Committee on July 17, and included presentations by ISO staff, Southern California Edison, and the Modesto Irrigation District on proposed GMC structures for 2004. Additionally, California Department of Water Resources/State Water Project and San Diego Gas & Electric presented their views as to changes that should be made to one or more of these proposals. ISO staff also presented a comparison of the common elements and differences among the proposals, and a listing of the 2004 GMC Rate Structure Project objectives that could serve as a basis for evaluating the proposals. The Committee requested additional information to aid in the evaluation of the proposals, including the extent to which billing determinants might be correlated, and comments by the proposal proponents on how the competing proposals might be deficient in reflecting the principle of cost causation. Such information will be provided prior to July 24. Other comments on the stakeholder process or the proposals were made by representatives from the California Municipal Utilities Association, California Public Utilities Commission, Electricity Oversight Board, and the Cogeneration Association of California/Energy Producers & Users Coalition.

The ISO recognizes and appreciates the work that participants in the 2004 GMC Rate Structure project have invested, and has endeavored to make use of the collective insights and feedback provided by this group in developing the ISO proposal. While unfortunately the group has not reached consensus on a single GMC rate structure proposal (the ISO's or otherwise), we believe that parties could agree that there has been a fair exchange of views and consideration of alternatives.

As the time has come to proceed with the preparation of the ISO's budget and rate filing for October, a decision on the rate structure is now required. ISO Management recommends adoption of the ISO's 2004 Rate Structure Proposal, as this proposal meets the important objectives set forth in the project charter (as outlined in the prior memorandum to the Committee), represents a justifiable evolution and improvement upon the current GMC structure, is responsive to the issues raised in previous proceedings, and many of those raised by stakeholders. We recognize that there will be continue to be opportunities to examine the implementation of certain of the elements of the ISO's proposal prior to the FERC filing in late October, and are prepared to work on the resolution of any remaining issues of concern to the Committee. The ISO intends to develop proposed rates incorporating the new rate structure and the proposed 2004 budget for publication and discussion by mid-September.

Consistent with this, ISO Management recommends adoption of the following motion:

MOVED, that the Finance Committee recommends the adoption of the ISO proposal for the 2004 GMC Rate Structure, providing for the GMC to be recovered through the service categories and billing determinants as set forth in the ISO's presentation to the Committee on July 17.

ALCANTAR & KAHL LLP

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MEMORANDUM

To	CAISO Finance Committee Chairman Tim Gage
From	Rod Aoki Jim Ross
Date	July 22, 2003
Regarding	Comments on 2004 GMC Rate Proposals

The Cogeneration Association of California (CAC) and the Energy Producers and Users Coalition (EPUC) appreciate this opportunity to provide comments on the various proposals for the CAISO's 2004 GMC rate design that are presently before the Finance Committee for review.

I. Executive Summary

As presented at the meeting of the Finance Committee held on July 17, 2003, recent decisions by the Federal Energy Regulatory Commission require that charges imposed on retail loads served by customer generation (retail behind-the-meter loads) must reflect use of the CAISO grid in order to be consistent with cost causation principles. The proposals submitted by Southern California Edison (SCE) and the Modesto Irrigation District (MID) are consistent with the FERC decisions because charges are imposed on retail behind-the-meter loads under those proposals only when the CAISO grid is used. The CAISO and California Department of Water Resources (CDWR) proposals are not consistent with the FERC decisions in their present forms because they impose charges based in part upon a gross load billing determinant which does not reflect use of the CAISO grid.

II. Proposals that reflect use of the CAISO controlled grid are consistent with cost causation.

It is well settled that under the principle of cost causation, *"those who are responsible for the incurrence of costs [should] be the ones who bear"* the burden of those costs. *Louisiana Public Service Commission and the Council of the City of New Orleans*, 96 FERC ¶ 63,002 at 65,009 (2001), *citing System Energy Resources, Inc.*, 41 FERC ¶ 61,238 at 61,616 (1987).

Retail behind-the-meter load does not cause the CAISO to incur costs, nor does it benefit from CAISO services unless it is actually taking power from the grid. The CAISO should not perform real-time monitoring and dispatching of customer generation. Nor should the CAISO procure ancillary services for retail behind-the-meter load. Additionally, retail behind-the-meter load is not scheduled, so charges related to scheduling may not reasonably be allocated on a gross load basis. When retail behind-the-meter load that is normally served by customer generation utilizes the Grid (*e.g.*, in the event of a generator outage), the customer pays its full share of all applicable charges. The customer pays its full share of the CAISO's charges as part of its state-jurisdictional retail standby tariff service or by making other contractual arrangements for standby service. If such standby service arrangements utilize the CAISO's grid, appropriate CAISO charges apply based upon actual metered usage at the customer receipt point,[1] and subject to state jurisdictional oversight.

Strict application of cost-causation principles requires that the pricing of electric services for retail customers must be based on the cost of net load, the actual usage as measured at the customer's receipt point. For the purpose of allocating any transmission related charges, the load-ratio share calculated for customer generation must be based on the net load purchased from the grid as recorded at the receipt point.

Consistent with this principle, in its Opinion No. 463, 103 FERC ¶ 61,114 (May 2, 2003), the FERC held in pertinent part as follows:

> 28. *However, the Commission believes that the judge cast too wide a net with the gross load approach in one respect. Customers with behind-the-meter generation who primarily rely on that generation to meet their energy needs have made a convincing argument that use of gross load results in this customer class being allocated too great a share of CAS costs. To take into account the more limited impact such customers have on the ISO's grid, the Commission finds that they should be allocated CAS costs on the basis of their highest monthly demand placed on the ISO's grid, rather than on gross load. In this manner, their more limited dependence on the ISO grid will be reflected in their allocation of the CAS costs. Customers eligible for such treatment are those with generators with a 50 percent or greater capacity factor.*[2]

Additionally, in a recent Order on Rehearing, 104 FERC ¶ 61,062 (July 10, 2003), FERC held:

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1 The point(s) of the end-use customer's interconnection with the CAISO's publicly dedicated wires; typically located at the site boundary.

2 Various parties have filed petitions for clarification and/or rehearing of Opinion No. 463, however, no party has challenged the Commission's rejection of a gross load billing determinant for retail behind-the-meter load. An order on rehearing is expected from the Commission on October 2, 2003.

> 55. *However, consistent with the treatment of behind the meter generation for purposes of the ISO's Control Area Services portion of the Grid Management Charge (GMC), we find that customers that primarily rely on behind the meter generation to meet their energy needs are allocated too great a share of the TAC. Instead, these customers should pay the TAC on a* ***net load*** *basis, i.e., the actual cumulative kWh load that utilized the grid in any given month,* ***to reflect their use of the grid*** *to access alternative resources, rather than on the basis of gross load. As with the GMC, customers eligible for such treatment are those with generators with a 50 percent or greater capacity factor. Accordingly, we grant rehearing in part. We will direct the ISO to submit tariff sheets to implement this change, on a prospective basis.* (Emphasis added).

To be consistent with the cost-causation principle, the appropriate point for determining the contribution that customers employing customer generation make to the CAISO grid system load is the customer's receipt point. This point is the correct location for determining the customer's relevant load (including any standby service provided by utility suppliers). The receipt point determination reflects the customer's actual use of the grid that imposes costs on the CAISO.

As summarized in the Memorandum to the Finance Committee from CAISO Staff dated July 9, 2003 (Staff Memorandum), the SCE and MID proposals assess charges to retail load served by customer generation only when that load uses the CAISO Controlled Grid. (Staff Memorandum at 10). Accordingly, those proposals are consistent with the FERC decisions cited above.

III. Proposals that utilize a gross load billing determinant are not consistent with cost causation but can be made consistent by utilizing a net load billing determinant.

As stated in the Staff Memorandum, "[t]he ISO's GMC proposal would assess some GMC (the Core Reliability Service charge) to load within the Control Area but not using the ISO Controlled Grid." (Staff Memorandum at 10) (Emphasis added). This is inconsistent with the FERC decisions cited above. Similarly, as the CDWR proposal largely mirrors the CAISO's proposal except for CDWR's proposal to base the billing determinant for Core Reliability Services (CRS) on monthly coincident peak demand rather than noncoincident peak demand, CDWR's proposal also is inconsistent with the FERC decisions.

The CAISO and CDWR proposals could be made consistent with the FERC decisions, simply by changing the billing determinant for the CRS to a net load rather than gross load basis. This would cause the charges imposed to properly reflect use of the CAISO grid.

IV. In addition to cost causation it is also appropriate for the Committee to examine any unintended adverse billing impacts which may discourage participation in the CAISO markets and attempt to mitigate those impacts where possible.

As stated in the Staff Memorandum,

> *... various analyses were performed on each proposal to determine the extent to which individual scheduling coordinators would pay significantly more or less than under the current GMC structure. While such cost shifts may be warranted based on the principles of cost causation, significant shifts may be inappropriate or unacceptable for other reasons, including equity, the impact on smaller customers, and the potential need to phase-in large changes over time.*

Based upon an examination of the rate impacts provided by CAISO Staff, it has been determined that each of the proposals before the Committee have the potential to cause adverse impacts to small scheduling coordinators. In some cases, the scheduling charge imposed by those proposals results in increases of up to 700% in the rates which small scheduling coordinators will be required to pay. While the scheduling charge may prove to be consistent with cost causation principles, the Committee may wish to consider mitigation of these adverse impacts through a graduated increase in rates for these entities.

Related to this issue is the quality of the data underlying the cost impacts that have been provided to date. While the work of CAISO staff in developing the data is appreciated, there are notable discrepancies in some of the data which suggests that cost increases reflected in the impact analyses may be understated. The Committee should insure that it has cost impact analyses that accurately reflect the impact on individual scheduling coordinators so that it can make reasoned decisions in mitigating bill impacts.

Respectfully Submitted,

July 22, 2003

To: **ISO Finance Committee**

From: **California Department of Water Resources, State Water Project**

Subject: **Critique of Coincident/Non-Coincident Peak Methodologies' Effects on Cost Principles**

As requested by the Finance Committee during the meeting on July 17, the California Department of Water Resources, State Water Project (CDWR/SWP) is pleased to be given a further opportunity to summarize the reasons why its proposal for a 12-month coincident peak methodology for the Core Reliability Services category of the GMC best reflects cost causation principles.

By assessing customers based on their contributions to the system peak, rather than on their non-coincident individual peak demands, the coincident peak method sends market signals which encourage the use of the grid during non–peak times. Benefits to using the grid during non-peak periods include reducing grid congestion, and reducing demand spikes. Both of these benefits reduce the overall costs of operating the grid, allow the ISO to more efficiently manage the grid, and mitigate the need for ongoing grid expansion. In contrast, a non-coincident peak method provides no incentives for time-efficient usage of the grid. If customers use the grid whenever it's most convenient to the customer, the demands placed on already peak hours and days will be increased, leading inevitably to a greater need for grid expansion sooner, and greatly exacerbating the likelihood of outage periods in the interim.

As a basic matter, the existing system was simply not planned or built to serve non-coincident loads. More importantly for present purposes, a non-coincident peak method such as proposed by the ISO staff does not reflect the way in which the California ISO in fact plans and manages its system. The ISO's current reliability assessment of future operations for planning purposes is based on the fundamental assumption that loads modeled in power flow cases "will represent a maximum anticipated *coincident* peak for the Cal-ISO Control Area…," and that "the distribution of the Cal-ISO load across the PTO areas was *based on simultaneous peak load measured during the peak hours*." 2002 California ISO Controlled Grid Study Report (February 21, 2003). These unsurprising assumptions strongly support SWP's proposal.

The belief that the GMC is not for recovery of planning costs, as stated by ISO staff consultants during the July 17 meeting in response to SWP's proposal, is fundamentally at odds with the ISO's Grid Study Report described above, as well as with the ISO Staff's own proposal here. In describing the Core Reliability Services category which is the subject of this disagreement, the ISO's June 25 "White Paper" states that: "In this sub-function [CRS], the *California ISO provides a stable grid and meets regional and national regulatory requirements* (such as NERC and WECC reliability criteria) and some FERC requirements (*such as a basic level of transmission planning*)." California ISO Rate Structure Proposal (revised June 25, 2003), p. 4, section 2.1.1. Among the activities described as included with Core Reliability Services are "Compliance with reliability standards," "Management, monitoring and approval of new generator interconnections," "*Evaluation of transmission expansion*," and "Performance of operational studies, system security analyses *and system planning studies* to ensure overall reliability." California ISO Rate Structure Proposal (revised June 25, 2003), p. 4, section 2.1.

The non-coincident peak method is also inherently inconsistent with fundamental concepts of utility planning as expressed in FERC Order No. 888, which states that "We are reaffirming the use of a twelve monthly coincident peak (12-CP) allocation method because we believe the majority of utilities plan their systems to meet their twelve monthly peaks." Order No. 888, p. 296, FERC Stats. & Regs. ¶ 31,063 at 31,736. It is to be noted that Order 888 did not pronounce a new policy in this regard, but rather was in the form of "reaffirming" long-standing utility planning and operational concepts and policies. The ISO staff has not suggested that the utilities comprising the ISO grid were planned or built on a non-coincident peak basis.

In sum, the coincident peak methodology is consistent with the manner in which the ISO grid was built, and is managed, planned, and operated. It is supported by the ISO's Grid Survey Report, the ISO Staff's description of Core Reliability Services, and fundamental concepts of utility planning and pricing, as expressed in Order No. 888 and other wholesale tariffs on file at FERC, such as the Midwest ISO's Open Access Tariff, sec. 34.2 ("...the Network Customer's monthly Network Load will be its hourly load *coincident with the monthly peak of the Transmission Owner*...."). A non-coincident peak methodology is necessarily inconsistent with all of these considerations.

Any questions concerning SWP's position may be addressed to:

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TO:	Finance Committee Chairman Gage, California Independent System Operator
FROM:	Dr. Laurence D. Kirsch
DATE:	July 22, 2003
SUBJECT:	Critique of the Other Rate Design Proposals

In response to your request at last Thursday's Finance Committee meeting, I am providing the following critique of the other rate design proposals. My critique is based upon the observation that a charge can reasonably reflect cost causation only if: a) the charge is for a real service that is actually used by the customer; and b) the billing determinant measures customer behavior or otherwise bears some plausible relationship to the cost of the service being charged. A charge will not reasonably reflect cost causation if it is merely a tax on customers for *activities* performed by the producer.

For example, the apple market provides a clear distinction between the service that customers use and the activities that the producer performs. Charges for apples are based on the number (or weight) of apples that the customer buys because the final product, apples, is what customers use. Although pest control is an activity that is essential to the reliable production of apples, there is no separate charge for "pest control service" or "reliability service": the cost of this activity is implicit in the price of the apples, and is not recovered through a "reliability service" charge on something other than apples.

The fundamental flaw of the other parties' GMC proposals is that they all seek to recover substantial portions of ISO costs according to ISO activities and processes rather than according to services used by customers. Although these activities and processes have been styled as "services" for the purpose of the various proposals, these "services" exist only as ratemaking fictions. Consequently, both their cost allocations and their billing determinants substantially fail to reflect cost causation.

1. THE ISO STAFF PROPOSAL[1]

Some elements of the Staff's proposal more or less adhere to the principle that customers should pay for the services they use, while other elements are nothing other than taxes designed to raise revenue. The elements that reasonably (though only partially) reflect cost causation are:

- *Energy and Transmission Services.* The "Net Control Area Load plus exports" billing determinant is an implicit measure of customers' use of the ISO's management of flows over the ISO-Controlled Grid. The "net uninstructed deviations" billing determinant is a measure of customers' use of the ISO's management of power imbalances.
- *Congestion Management.* The "Net Scheduled Interzonal load flows" billing determinant is a measure of customers' use of the ISO's management of flows over the ISO-Controlled Grid.
- *Market Usage.* The purchases and sales of energy and ancillary services in ISO-administered markets is a measure of customers' use of these markets.

Unfortunately, Staff has assigned only 33% of the ISO's revenue requirement to the foregoing services. It has assigned the other 67% of the ISO's revenue requirement to rate categories that are poorly designed or outright fictitious:

- *Core Reliability Services* is a ratemaking fiction rather than a service that is physically separable from the ISO's power balancing and transmission flows management services.
- *Settlements, Metering, and Client Relations* recovers costs through explicit taxes on the ISO's other services rather than through charges that are plausibly related to the costs of Settlements, Metering, and Client Relations.
- *Forward Scheduling Service* has a billing determinant that is not based on customer schedules but is instead based on ISO internal accounting practices.

Because these latter rate categories recover costs in a manner that is poorly related to cost causation, they lead to inequitable cost recovery and they can provide poor incentives for the ISO to efficiently size its business in response to customer demand for its services. The specific deficiencies with these poorly designed rate categories are described below.

1.1. Core Reliability Services

"Reliability" is a measure of the quality of the ISO's fundamental services (i.e., power balancing and transmission flow management), rather than a service with an existence separate from these fundamental services. The reliability of the ISO's fundamental services is no more separable from those fundamental services than the reliability of a car is separable from the car; and just as the costs of a car's reliability are recovered through the price of the car, so the costs of the power system's reliability should be recovered through the prices of the power system's fundamental services.

[1] P. Leiber and D. LeVine, *Rate Structure Proposal For the 2004 GMC Rate Structure Project*, California ISO, July 9, 2003.

Core Reliability Services (CRS) and Energy and Transmission Services (ETS) together comprise "Grid Reliability Services." CRS and ETS both recover the same categories of costs, but they have different billing determinants. This difference in billing determinants is every bit as odd as recovering the fixed costs of apple orchards through a tax on anyone who has ever eaten an apple while recovering the variable costs of apple-picking from consumers according to the number of apples that they buy. The ISO Staff has proposed to recover what it characterizes as the "non-scalable" costs of Grid Reliability Services through a tax that is unrelated to customers' use of ISO services, while recovering the "scalable" costs through charges that are related to customers' use. This inconsistency arises from the artificiality of the CRS category. The solution is to recover CRS costs – which are all related to managing imbalances and transmission flows – through the same billing determinants as are used for the ETS category. Unlike the CRS category, the ETS category recovers costs through charges that are related to a customers' use (net control area load plus exports, and net uninstructed deviations).

We agree with Staff that all customers benefit from the ISO's services. But because customers use the ISO services differently, they do not benefit equally on either a per-SC basis or on a per-MW of gross load basis. As the FERC noted in its Opinion and Order of May 2, 2003 ("Opinion No. 463"), "Customers with behind-the-meter generation who primarily rely on that generation to meet their energy needs have made a convincing argument that use of gross load results in this customer class being allocated too great a share of CAS [Control Area Services] costs."[2] FERC clearly recognized that different ISO customers impose different cost burdens on the ISO according to their different uses of the ISO-Controlled Grid, and that the ISO's current GMC rate design, particularly the CAS component, does not capture this principle. Unfortunately, the proposed CRS mimics the current CAS' violation of the cost causation principles that FERC identified in Opinion No. 463. Although Staff has partly addressed these principles by assigning 29% of Grid Reliability Services to the ETS categories, it has left the remaining 71% of Grid Reliability Costs in CRS and thus in violation of the principles of Opinion No. 463.

1.2. Settlements, Metering, and Client Relations

The first problem with this category is the seeming disproportion between its $47.9 million dollar cost and its output of roughly a hundred customer bills per month. Any defense of this category will need to begin with an explanation of this relationship between cost and output.

The second problem is that ISO Staff proposes to recover the costs of this category through several charges that bear no obvious relationship to the possible causes of these costs.[3] These costs might depend upon customer behaviors and characteristics like the customer's number of transactions, number of metering points, types of metering communications hardware, etc. But, at Table 4, the Staff instead proposes to recover this category's costs through:

- a $0.109 per MWh tax on Controlled Grid Load plus exports;
- a $0.398 per MWh tax on net uninstructed deviations in each interval;

[2] "Opinion and Order on Initial Decision," *California Independent System Operator Corp.*, 103 FERC ¶ 61,114 at at P.28, Docket Nos. ER01-313, *et al.* (May 2, 2003).

[3] The exception is the proposed $500 per month per SC charge, which may reasonably represent how the ISO's monthly costs vary with the number of SCs.

- a $0.050 per MWh tax on inter-zonal flows; and
- a $0.220 per MWh tax on market usage

These are taxes because there is no discernable relationship between these billing determinants and Settlements, Metering, and Client Relations costs. For example, it does not seem plausible that, all other things being equal, an SC with 10,000 MWh of inter-zonal flows will have a larger impact on Settlements, Metering, and Client Relations costs than an SC with 10,000 MWh of intra-zonal flows; yet the proposal will charge the former SC an extra $500 relative to the latter SC.

1.3. Forward Scheduling Service

To reasonably reflect cost causation, a "service" must be used by a customer and the billing determinants must reasonably reflect such use. The Forward Scheduling Service charge does not reasonably reflect cost causation because it merely redefines the ISO's internal accounting processes as a "service."

Furthermore, we understand that Staff's proposal counts as a "schedule" and levies an equal charge on at least each of the following:

a) provision by a generator of energy output in each hour;

b) provision by a generator of regulation service in each hour;

c) provision by a generator of spinning reserve service in each hour;

d) an SC's aggregate load behind each ISO metering point in each hour;

e) an SC's export at each export point in each hour;

f) an SC's import at each import point in each hour; and

g) an SC's trade with another SC in each hour.

It is not obvious to us that the ISO's costs of handling each of these "schedules" are approximately equal. For example, an SC that is responsible for a generator that submits one schedule for a constant 100 MW of energy for every hour during the next five days would be charged for 120 "schedules" (5 days times 24 hours per day); while another SC that is responsible for a generator that schedules a different output level every hour of the next five days, and that repeatedly changed its scheduled amounts, would also pay for 120 schedules. As another example, a generator that helps system reliability by offering regulation service would pay twice as much for Forward Scheduling Service as a generator that offers only energy.[4]

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[4] The former generator would be charged for one energy schedule and one regulation schedule. The latter generator would be charged for one energy schedule.

2. THE CDWR PROPOSAL[5]

The CDWR proposal is identical to the ISO Staff proposal except that the billing determinant for Core Reliability Services (CRS) is coincident peak demand rather than non-coincident peak demand. This difference does not address the problems that: a) CRS exists only as a ratemaking fiction; b) CRS violates the cost causation principles that FERC identified in Opinion No. 463; nor c) the billing determinant only partly overlaps with those SC behaviors and characteristics that contribute to reliability problems. Consequently, the CDWR proposal fails to reflect cost causation to exactly the same extent as the ISO Staff proposal fails to reflect cost causation.

3. THE SCE PROPOSAL[6]

Like the ISO Staff's Core Reliability Services, SCE's *Control Area Services* is a ratemaking fiction rather than a service that is physically separable from the ISO's power balancing and transmission flows management services. It therefore suffers the same deficiencies as Core Reliability Services.

Dynamic Dispatch Export Service is a vehicle by which SCE proposes to distinguish its use of Control Area Services from that of other SCs. SCE is essentially saying that its own proposed billing determinant for Control Area Services is a poor measure of customers' use of the ISO's services. To address the alleged inequity in its payments for Control Area Services, SCE proposes that it pay 10% of the rate for Control Area Services. This 10% figure lacks any cost justification. Rather, it is an attempt by SCE resolve an ongoing dispute as to whether or not GMC is appropriately charged on energy that is dynamically scheduled out of the ISO control area over transmission that has not been explicitly turned over to the operational control of the ISO. While SCE's concerns (and the similar concerns raised by SDG&E) may be legitimate, the best approach for resolving this dispute is for the ISO to adopt reasonable measures of how different customers use the ISO's fundamental services, so that the same measures can be equitably applied to all customers.

For *Scheduling Service*, there is no obvious relationship between the costs of this service and the proposed billing determinant of MWhs of energy scheduled plus MWh of self-provided ancillary services.

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[5] California Department of Water Resources, *Position Paper on The Independent System Operator 2004 Grid Management Charge Rate Structure Proposal*, July 16, 2003.

[6] California Edison Edison, *California ISO Grid Management Charge: Conceptual Proposal and Southern California Edison*, February 19, 2003; and *SCE GMC Proposal Rates*, about April 28, 2003.

CALIFORNIA ISO

California Independent
System Operator

California ISO

Commentary on Proposed Billing Determinants and their Effects on ISO Revenue Stability

&

The Use of the Principle of Cost Causation in the MID, SCE and California ISO GMC Proposals

Developed in Response to ISO Finance Committee Inquiries of July 17, 2003

Table of Contents

1. Introduction

The following commentary is provided in response to Finance Committee Chairman Gage's request for the sponsors of each GMC proposal to address the following issues:

1. How the billing determinants used in each proposal are likely to affect the revenue stability of the ISO.

2. How the principle of cost causation is achieved (or not) in the alternative GMC proposals.

2. Observations on Billing Determinant Stability and the Effect on ISO Revenue Adequacy

These comments are made with respect to the ISO and MID proposals. Given the recent changes and resulting uncertainty about the status of SCE's GMC proposal, we do not believe a comparable analysis of that proposal is possible at this time.

A. Which billing determinants are likely to be difficult to forecast with a reasonable degree of accuracy for 2004?

ISO rates are to be set in advance. This requires developing the 2004 ISO revenue requirement, attributing those costs to the GMC service categories, and then forecasting billing determinant volumes to arrive at the rates for each GMC service category.

Forecasting certain billing determinant volumes could be a significant challenge. This is due to billing determinants that have been historically volatile or otherwise difficult to predict, or anticipated future market changes that will have an effect on the billing determinant. In the table that follows, we subjectively assess the accuracy of any billing determinant forecast and provide a ratio of the billing determinant volumes for two previous periods as a measure of how stable the billing determinant has historically been. The deviation of that ratio from 100% (in either direction) is a measure of the determinants instability.

ISO Proposal

Service	Billing Determinant and [% of ISO Revenue Recovered over this measure]	Subjective assessment of likely accuracy of forecast (1=very inaccurate through 10=very accurate)	2002/03 volume divided by comparable period from 2001/02 (as measure of billing determinant stability)
Core Reliability:	Non-Coincident Peak Demand [39%]	**Rating: 8**: Monthly peak demands aggregated over a year are likely to be somewhat less amenable to accurate forecasts than overall energy consumption.	97%

Energy and Transmission	Grid Usage (Load and exports in MWh) [24%] Net uninstructed deviations (MWh) [6%]	**Rating 9:** Actual results not likely to deviate from forecast by more than 3% for the year. **Rating 6:** The effect of MD02 Phase 1B penalties will have to be assessed.	100% 108%
Forward Scheduling	Count of number of final Hour-Ahead schedules processed [8%]	**Rating 6:** Variability of number of schedules depends on schedule type. Load schedules are quite stable and generation schedules even more so. Of the various schedule types, inter-SC trades will be the most difficult to predict (and these comprise 40% of the # of all schedules). With these schedules, there is also the potential for price elasticity. The current expectation is that any effect will be small because the charge itself is small relative to the cost of the scheduled power.	105%
Congestion Management	Net scheduled Hour-Ahead interzonal flows (MWh) [6%]	**Rating 6:** Amounts have historically been more difficult to forecast than overall energy consumption. May need to assess expected date for switch to LMP during 2004, which would eliminate this billing determinant.	110%
Market Usage	Purchases and sales of Ancillary Services, Instructed Energy and net uninstructed deviations (MWh) [16%]	**Rating 5:** Historically this has been a volatile billing determinant. 2001 was particularly volatile, while other years have been much less so. Volatile components are instructed energy and Net uninstructed energy. Market procured A/S has been volatile in the past, but appears to have stabilized.	85%
Settlements, Metering & Client Relations	Customer months [<1%]	**Rating 8:** Number of SC IDs not anticipated to vary substantially from a forecast. Since this is not a significant source of revenue, it is not as important to forecast accurately.	Not calculated

MID

Service	Billing Determinant and [% of ISO Revenue Recovered over this measure]	Subjective assessment of likely accuracy of forecast (1=very inaccurate through 10=very accurate)	2002/03 volume divided by comparable period from 2001/02 (as measure of billing determinant stability)
Resolving Energy Imbalances	Uninstructed Deviations, energy and demand, with two tiers. [Energy 6%], [Demand 12%]	**Rating 5:** For uninstructed deviation demand, which is likely to be more difficult to predict than uninstructed deviations-energy. For tiers, the higher cost tiers are likely to be harder to predict due to a potential behavioral effect). Additionally, the effect of MD02 Phase IB penalties will have to be assessed.	105%
		Rating 6: For energy, and for lower tiers. The effect of MD02 Phase 1B penalties will have to be assessed.	108%
	Number of SCs [<0.1%]	**Rating 8:** Number of SC IDs not anticipated to vary substantially from forecast.	Not calculated
Managing Transmission Flows	Power withdrawals [54%]	**Rating 9:** Actual results not likely to deviate from forecast by more than 3% for the year.	100%
	Number of SCs [<0.25%]	**Rating 8:** Number of SC IDs not anticipated to vary substantially from a forecast.	Not calculated
Administering Markets	Energy Trading Volumes [5%] AS Trading Volumes [23%] [Total: 28%]	**Rating 5:** Historically this has been a volatile billing determinant. 2001 was particularly volatile, while other years have been much less so.	76% 71%

B. If overall energy consumption increases or decreases, how are the billing determinants likely to be affected?

Billing determinants for the 2004 rate structure will be forecast this summer. Actual results are likely to differ from the forecast due to a variety of reasons. For overall energy consumption, these include changes in economic activity, population, conservation efforts, and weather patterns both in and outside of California. Certain of the GMC billing determinants might be influenced by these general trends in the same manner as overall energy consumption. However, there are numerous exceptions to this, which are discussed below.

Note: These observations are made on the basis of the informed opinion of ISO staff, but have not been tested through the statistical analysis of historical billing determinant data.

ISO Proposal

Service	Billing Determinant	Relationship to Energy Usage
Core Reliability:	Non-Coincident Peak Demand	Non-volumetric, but strongly correlated with overall energy consumption.
Energy and Transmission	Load and Exports (MWh) Net uninstructed deviations (MWh)	Volumetric: Load & Exports is overall energy consumption. Volumetric: Net uninstructed deviations not strongly correlated with energy consumption
Forward Scheduling	Count of number of final Hour-Ahead schedules processed	Independent of overall energy consumption.
Congestion Management	Net scheduled Hour-Ahead interzonal flows (MWh)	Volumetric: Strongly correlated with overall energy consumption.
Market Usage	Purchases and sales of Ancillary Services, Instructed Energy and net uninstructed deviations (MWh)	Volumetric: Not directly correlated with overall energy consumption. Changes in demand not foreseen over a longer planning horizon are likely to increase volumes here as such volumes are likely to be met in the spot and planned day-ahead market rather than through longer term bilateral contracts.
Settlements, Metering & Client Relations	Customer months	Non-Volumetric: Independent of overall energy consumption.

MID Proposal

Service	Billing Determinant	Relationship to Energy Usage
Resolving Energy Imbalances	Uninstructed Deviations, energy and demand Number of SCs	Volumetric: Net uninstructed deviations not strongly correlated with energy consumption Non-Volumetric: Independent of overall energy consumption.
Managing Transmission Flows	Power withdrawals Number of SCs	Volumetric: Is a measure of overall energy consumption. Non-Volumetric: Independent of overall energy consumption.
Administering Markets	Energy Trading Volumes AS Trading Volumes	Volumetric: Not directly correlated with overall energy consumption. Changes in demand not foreseen over a longer planning horizon are likely to increase volumes here as such volumes are likely to be met in the spot and planned day-ahead market rather than through longer term bilateral contracts.

C. To what extent are the billing determinants inversely correlated, such that a decrease in volumes of one billing determinant might be offset by an increase in another, thereby helping the ISO to remain revenue-neutral overall?

Note: These observations are made on the basis of the informed opinion of ISO staff, but have not been tested through the statistical analysis of historical billing determinant data.

The ISO does not anticipate that there will exist any significant "portfolio" effect, such that a significant decrease in one billing determinant would likely be offset by a significant increase in another. However, this could occur, by chance. Additionally, as each service category is to be treated as financially separate, the ISO Tariff provides that rates may be adjusted quarterly (See Section D of this document) if the annual billing determinant is anticipated to deviate from the volume used to set the rate by more than 5%. If these adjustments were not made, any revenue shortfalls (or over-collections) would be applied to the following year, and this shifting of monies from one year to the next is to be avoided if possible.[1]

ISO Proposal

Market volumes could be higher than anticipated if overall energy demand is lower than anticipated, as Scheduling Coordinators attempt to sell excess energy to other users through the ISO's real-time or day-ahead markets (though this might not lead to an increase in transactions, if there were no users found for this power.)

The same could be said of the billing determinant for Forward Scheduling: number of schedules submitted. There could be an increased volume of inter-SC trades in an environment where volumes are much higher or lower than anticipated.

MID Proposal

Market volumes could be higher than anticipated if overall energy demand is lower than anticipated, as Scheduling Coordinators attempt to off-load excess energy to other users through the real-time or day-ahead markets.

D. What tools are available to ensure that the ISO will have sufficient funds to meet its corporate financial obligations?

As a critical element of the State's energy infrastructure, it is important to ensure that the ISO has ongoing funding to meet its obligations to its employees, suppliers and contractors. When the ISO moved to an unbundled rate structure in January 2001, the GMC revenue stream was subjected to additional volatility from unanticipated changes in billing determinant volumes.

The effect of shortfalls in GMC revenues on the ISO's financial stability can be addressed through the following:

[1] A component of the principle of cost causation is that the users of a service should pay for its costs. A given year's users of an ISO service should pay for the costs, not another year's users.

	Measure	Explanation
1	Financial Operating Reserve	The ISO Tariff provides for an operating reserve equal to 15% of the O&M budget, or about $26 million.[2] This reserve is funded through collecting 125% of required annual debt service. This reserve can be drawn down in months where expenditures exceed revenues.
2	Quarterly GMC Rate Adjustments	ISO Tariff provides that GMC rates for any given GMC service category may be adjusted quarterly if forecasted volumes for the year are expected to deviate by more than 5% from budgeted volumes for the year.
3	Line of Credit	An uncommitted bank line of credit may be available without up-front cost. A committed line of credit may be available at a cost of several hundred thousand dollars annually. A line of credit has not been available to the ISO since 2001 given the ISO's lack of an investment-grade credit rating, but may be available in the future.
4	Forecasting Billing Determinants	In developing forecasts of anticipated billing determinant volumes where substantially uncertainty exists, base the rates on the lower-end of the estimate. If during the year, it appears that excess funds are to be collected, rates can be adjusted downward (through the quarterly adjustment mechanism) or returned to ratepayers through lower rates in the subsequent year.
5	Slow or Reduce Expenditures	Defer non-critical projects or spending until financial stability is restored. The ISO enacted such measures during the spring of 2001 when GMC collections were put at risk due to the PG&E bankruptcy. While the majority of the ISO's spending is for items that are committed (staffing, service contracts, insurance), some spending can be postponed, such as consulting/contracting work, certain capital projects, travel, training, etc.

[2] Any excess funds in the reserve beyond that level are to be applied as a reduction in the subsequent year's revenue requirement, and is thus returned to ratepayers.

3. Observations on the Use of the Principle of Cost Causation in the Alternative GMC Proposals

This commentary examines selected aspects of the alternate GMC proposals, with specific emphasis on their accord with the principle of cost causation[3].

The three proposals (ISO, SCE[4] and MID) have certain similarities. Each explicitly recognizes the ISO's role in providing markets through a separate market function.[5] Each proposal recognizes the ISO's role in managing real time imbalances through the use of net uninstructed deviations as a billing determinant for one or more service categories. However, the proposals differ in the method to be utilized to recover the ISO's costs of providing reliability as well as their use of a relatively volatile variable as a billing determinant for certain categories. The former stems from a philosophical difference in their view of the ISO's role as the Control Area operator. We organize our comments around the differences in the view of the reliability function and other billing determinant issues.

Reliability Function

The ISO performs a number of activities to provide for reliability. These activities include monitoring and maintaining transmission operation, generation and transmission outage coordination, inter-tie prescheduling, transmission planning, and real time grid operations. These activities continue regardless of the time of day or the season. The ISO's provision of reliability services benefits all entities in the Control Area, whether or not they are part of the ISO Controlled Grid[6]. Under cost causation principles, the costs of providing reliability services should be assessed on all entities in the Control Area. The ISO's view is that the appropriate method of apportioning these costs to users is to consider each SC's maximum usage (non-coincident peak) in the ISO Control Area regardless of the time of day, because this reflects the SC's greatest reliance (on a relative basis) upon the ISO's reliability services during the month.

It is also appropriate to assess SCs on a gross basis. We believe that entities that meet a portion of their requirements with "behind the meter" generation should also pay for reliability services enjoyed by being part of the interconnected grid. FERC's recent Order 463 on the 2001 GMC rate case requires that entities with behind the meter Load (with a capacity factor of greater than 50%) be assessed GMC on the basis of a demand charge. The ISO believes a demand

[3] In simple terms, cost causation principles require that cost responsibility match as closely as practicable the cost of providing a service.
[4] As presented throughout most of the stakeholder process. SCE's position, as presented at the July 17, 2003 Finance Committee meeting, was that it would not further pursue its proposal if certain modifications were made to the ISO proposal. These modifications included exempting certain energy (certain Mohave and Southwest Power Link volumes) from the definition of "Exports" in the ISO Tariff, thereby exempting such volume from the assessment of GMC charges. To date, the ISO has not received from SCE sufficient support for this proposal to demonstrate that it would be consistent with the principle of cost-causation.
[5] The ISO's market function is called Market Services; SCE's is called Market Operations Services; and MID's is called Administering Markets.
[6] The Control Area consists of the entire geographic area of ISO's operational influence and includes the transmission of both Participating and non-Participating Transmission Owners. The Controlled Grid includes only the transmission of Participating Transmission Owners.

charge is also appropriate for all entities. If reliability services were assessed only on a net basis, some entities could reap the benefits of being linked to the interconnected grid without paying what the ISO views is their appropriate share of the costs of these benefits. Accordingly, their costs would be effectively subsidized by the rest of the Control Area. The ISO's position on using gross Load for this GMC issue is also consistent with that taken by the ISO in other, related forums. The ISO believes it has the responsibility, based on WECC requirements, to consider all Load in the Control Area in its actions to ensure reliability.

All three proposals, the ISO's, SCE's and MID's, have a reliability service component. The ISO's reliability function is called Grid Reliability Services and has two subfunctions, Core Reliability (CRS) and Energy and Transmission Services (ETS). CRS is assessed on gross metered non-coincident peak demand.

SCE's reliability function is contained within its Control Area Services (CAS). In SCE's proposal, only wholesale behind the meter Load (principally, Load of governmental entities not part of the ISO Controlled Grid) would be assessed the CAS. SCE would exempt retail behind the meter Load from the CAS. This is inconsistent treatment of Load in the Control Area. Physically, retail and wholesale behind the meter Load is identical. The ISO must monitor and maintain reliability for all Load, regardless of where it is located. Not charging all behind the meter Load is not consistent with cost causation principles.

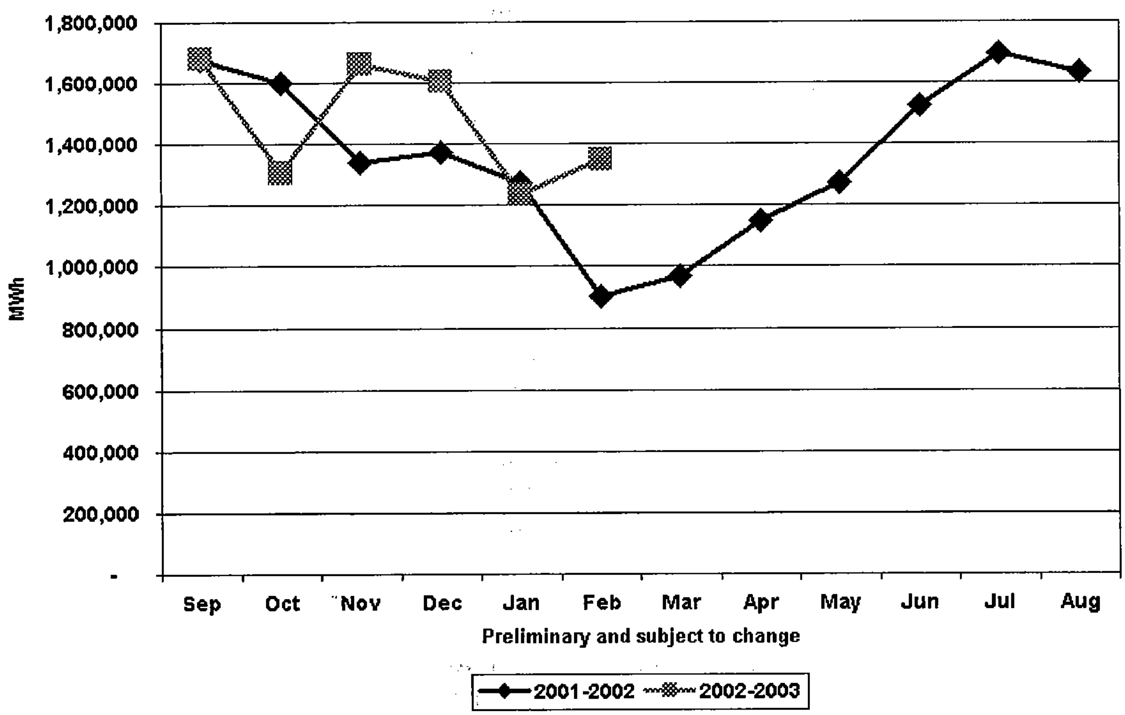
MID's reliability function can be found within both its Resolving Energy Imbalances (REI) and Managing Transmission Flows (MTF) functions. MID's use of net uninstructed deviations as the essentially the sole billing determinant for REI will be discussed below. MID proposes net control area Load plus exports as the billing determinant for the MTF. Net control area Load does not include behind retail or wholesale meter Load. As discussed previously, in the view of the ISO, excluding behind the meter Load is not appropriate on a cost-causation basis.

Billing Determinants

SCE proposes a Real-Time Market Operations Service with net uninstructed deviations as the sole billing determinant. MID proposes to use only net uninstructed deviations as the billing determinant for its Resolving Energy Imbalances function (apart from minor per SC charge to recover less than 0.25% of the costs in this category).

Net uninstructed deviations tend to be quite volatile on a monthly basis, a very undesirable characteristic for a sole billing determinant. This volatility can be seen in the chart below that shows monthly net uninstructed deviations from September 2001 through February 2003.

Comparison of Net Uninstructed Deviations
Sept. 2001 through Feb. 2003

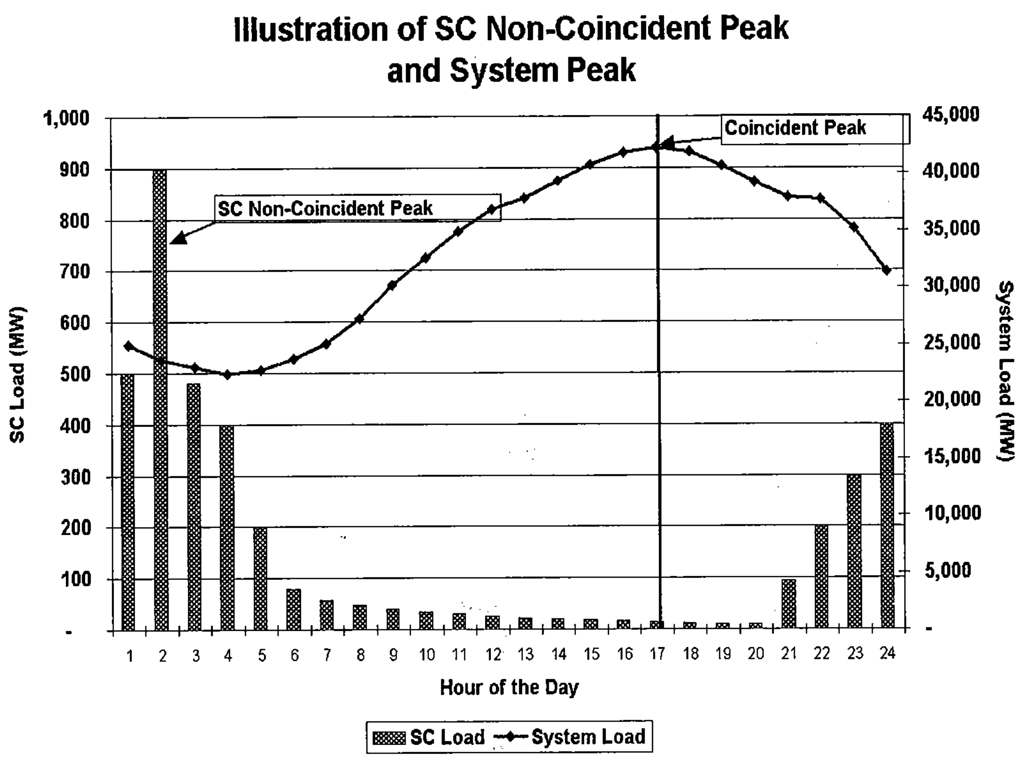


CDWR proposes that the Board adopt the ISO proposal with the exception of using coincident peak rather than non-coincident peak as the billing determinant of the ISO's CRS. As noted earlier, the non-coincident peak is the proper billing determinant as it captures each SC's impact on the Control Area regardless of the time of day. Using the coincident peak might mean that an SC that had peak usage at another time of day, e.g., in the early morning, would not contribute to recovery of CRS even though the ISO has provided system reliability for the SC to operate at that time. The chart below illustrates the difference between coincident peak and non-coincident peak for a hypothetical SC.

CDWR argues that using coincident peak provides the correct incentives to SCs to move Load to off-peak times. What CDWR does not state is that there already exist sufficient incentives for SCs to increase wholesale usage in off-peak hours[7]. Market prices, by far the largest component of an SC's energy cost, are typically lower in the off-peak period and would provide a much greater incentive to use off-peak energy. Increasing the cost of peak hour usage may have the effect of lowering the hour of system peak but increasing usage in the hours adjacent to the peak (the shoulder hours), which does not reduce the ISO's burden. Additionally,

[7] A much greater effect on peak usage could be created through the use of greater incentives on retail load to reduce peak usage.

this argument would place the goal of "shifting Load" to a non-peak period above the principle of encouraging a rate-structure for the ISO GMC based on cost-causation.



Summary

We believe the ISO proposal best meets the goals established at the beginning of the stakeholder process.

- It represents an unbiased and equitable approach to recover GMC costs. The proposal was not developed to minimize charges to any individual or group of participants.

- It provides for service categories and billing determinants that are based on the principle of cost-causation. The billing determinants for each category are, in the view of the ISO, appropriate and fair indicators of the cost-drivers for each category. The billing determinants for these categories are not anticipated to be inappropriately volatile or unpredictable. Any issues with revenue stability are expected to be duly addressed through a quarterly GMC adjustment mechanism as provided for in the current GMC, and with the other tools listed on page 8.

At the July 17 ISO Board Finance Committee meeting, Committee Chair Tim Gage requested that parties provide the Board members with their critiques of the proposals of other parties provided in the 2004 ISO GMC Stakeholder process. In response to this request, Southern California Edison (SCE) provides the following comments.

SCE COMMENTS ON ISO GMC PROPOSAL

SCE indicated at the meeting that we would be supportive of the ISO Staff's GMC proposal with two modifications which were necessary to render the ISO proposal just and reasonable. These two modifications -- comparable billing determinants that take into account behind-the-meter generation and special consideration of certain types of exports are described in full as follows.

1) The ISO Staff's proposal does not adopt comparable billing determinants for all GMC customers for the Core Reliability Services ("CRS") and Energy and Transmission Services ("ETS") components of the GMC and does not reduce the GMC assessment for behind-the-meter generation, as FERC has indicated is appropriate.

Taking guidance from the recent FERC Final Order issued for the ISO's 2001 GMC, the CRS Charge should be assessed to "Grid Demand." Grid Demand is the demand that a Scheduling Coordinator places on the ISO Controlled Grid. Grid Demand differs from "Gross Load Demand,"[1] the billing determinant in the ISO Staff's current proposal, in the case where a Scheduling Coordinator ("SC") has generation serving load "behind-the-meter" ("BTM"). BTM load served by BTM generation is included in "Gross Load Demand," but is not a part of "Grid Demand."

SCE believes that the FERC GMC Final Order provided the basis for an appropriate resolution of the issue of how much SCs with BTM generation should pay for the ISO's administrative costs. The key difference between the ISO Staff's proposal and SCE's proposal is how demand is measured under the two approaches. The Grid Demand approach measures peak load of an SC on the ISO Controlled Grid and reflects the fact that an SC may have BTM generation and BTM load. Thus, Scheduling Coordinators with BTM generation and BTM load will pay some of the ISO's GMC costs, but less than they would pay if the load were assessed on a "Gross Load Demand" basis, as proposed by the ISO Staff.

SCE would improve upon the guidance provided in the Final Order by making the CRS charge applicable to all SCs in a comparable and non-discriminatory manner. The CRS charge would be applicable to all SCs with "Grid Demand", without any requirement that the SC have a generator with a 50% capacity factor. Additionally, if an SC has generation located on distribution circuits, that generation is "behind-the-meter", and it should be considered in the determination of the SC's Grid Demand. In the case of SCE, this distribution-level generation represents about 6% of SCE's total load measured in a "bottom's up" manner from end-use customer meters. To convert the measured "bottom's up" load to Grid Demand for SCE, there should be an adjustment made each

[1] Labeled "Non-Coincident Peak Demand" in the ISO Staff's proposal.

month by subtracting this 6% factor from the measured "bottoms up" load. This adjustment factor should be revised annually. Each SC representing a distribution utility similarly situated to SCE, whose Grid Demand cannot be simply determined based on ISO meter data, should determine their own adjustment factor so that Grid Demand may be measured on a comparable basis for all SCs.

The ISO Staff's proposal for the CRS Charge fails to recognize the solution that FERC indicated was appropriate for BTM generation in its Final Order. Gross Load Demand is the demand charge equivalent to the energy billing determinant used in the 2001 GMC -- Control Area Gross Load -- and thus likely will engender the same protests and litigation as the 2001 GMC did. Grid Demand should be measured comparably for all entities and should take into account the Commission's decision on BTM generation; the ISO Staff's proposal does neither.

The ISO Staff has proposed that the billing determinant for the majority of ETS costs be "Net Control Area Load." SCE has not yet seen a definitive definition for this billing determinant. The ISO Staff has refused to provide any comprehensible written description of the billing determinant or explain how it would be measured. The ISO Staff must explain this billing determinant before the Board can accept this proposal. In any case, like the CRS charge, the ETS Charge should be measured in a non-discriminatory and comparable basis for all customers.

2) The ISO Staff's "definition" of "export" does not consider the unique aspects of exports that serve load in other control areas, are delivered over non-ISO Controlled Grid facilities, and are not the load responsibility of the ISO.

Under the ISO Tariff, the term "export" has never been defined, which led to litigation over the last GMC methodology and is certain to lead to more litigation as the ISO Staff continues to refuse to define the term, let alone define it appropriately. SCE's preferred resolution of this issue is that the term "export" be defined as follows:

> Export: The use of the ISO Controlled Grid for the transmission of Energy to serve a Load located outside the transmission and distribution system of a Participating TO.

The primary result of this approach would be that the CRS and the ETS components of the GMC would not be assessed to transactions such as those scheduled over the non-SCE shares of the Eldorado transmission system. The ISO does not normally have scheduling responsibility for non-ISO Controlled Grid facilities, but it does in the case of certain transmission lines owned jointly by non-PTOs and PTOs, such as COTP, the SWPL, and Eldorado system. (Other jointly-owned lines are scheduled by other control area operators.) Such loads, particularly where the load is not the load responsibility of the ISO, place minimum burdens on the ISO. The loads using such facilities to export already pay their own transmission providers for the equivalent of CRS and ETS in their OATT.

If the term export is not defined as noted above, SCE supports a reduced CRS and ETC Charge for exports not using ISO Controlled Grid facilities that serve load outside the ISO control area and are not the load responsibility of the ISO for the reasons described in its proposal.

SCE is supportive of the ISO Staff's proposal with these modifications.

SCE COMMENTS ON MID GMC PROPOSAL

To briefly summarize the MID proposal, it consists of three functions, as summarized in the table below:

Function	Allocated Costs	Billing Determinants	Rates
Resolving Energy Imbalances	$42.4 M	1) Uninstructed deviation energy (two tiers) 2) Uninstructed deviation demand (two tiers) 3) Number of SCs	1) $0.06 and $1.21 per MWh 2) $15 and $600 per MW-month 3) $125 per SC-month
Managing Trans-mission Flows	$128.3 M	1) Power Withdrawals 2) Number of SCs	1) $0.527 per MWh 2) $375 per SC-month
Adminis-tering Markets	$66.9 M	1) Energy trading volumes 2) Ancillary Services trading volumes	1) $2.28 per MWh 2) $2.28 per MWh

SCE's most fundamental disagreement with the MID proposal is the extent to which costs are allocated to functions that are voluntary for market participants, at the expense of functions that are mandatory. In the MID proposal, both the "Resolving Energy Imbalances" and "Administering Markets" functions may be avoided by a SC based on the behavior of the SC. The Resolving Energy Imbalances function may be avoided by not having "uninstructed deviation demand", and the Administering Markets function may be avoided by not participating in energy of ancillary services markets. In comparison, the "Managing Transmission Flows" is largely mandatory for all SCs.

This is reflected in the prices for MID's functions. In the MID proposal, it costs $2.28 per MWh to participate in an ISO ancillary service or energy market. In the ISO's proposal, it costs $0.85 per MWh. In SCE's opinion, this is due to an over allocation of costs to the Administering Markets function. An important role of the ISO is to promote economic efficiency through its energy and ancillary services markets. If the GMC charge to voluntary market activities is too high, as it is in the MID proposal, that goal will be compromised.

SCE's also has further specific concerns with the MID proposal, given how it has defined the ISO's functions. These are:

1) The MID proposed billing structure for the "Resolving Energy Imbalances" function is two tiered, with a lower rate for initial amounts of service, and a much higher rate for higher amounts of service. SCE does not believe there is a sound basis for this treatment.

2) The MID proposed billing determinant for the "Managing Transmission Flows" function, power withdrawals, discriminates against entities like SCE because it does not recognize amounts of energy served on distribution systems from generation located on the distribution system. It thus appears that MID's billing determinant suffers from some of the same flaws as the ISO Staff's billing determinant for its CRS charge, because it does not recognize the generation located on the distribution system.

MID has described its "power withdrawals" billing determinant as reflecting the actual use of the ISO Controlled Grid, but has not explained how it would measure such usage, where it is not in fact directly metered by the ISO. Just as the ISO should determine the billing determinant for its CRS function on a comparable basis for all SCs, MID's "power withdrawals" billing determinant should also be determined on a comparable basis for all SCs. This means that, for entities like SCE with generation located at the distribution level, there should be an adjustment made to the "bottoms up" end-use meter data to determine power withdrawals on a comparable basis.

3) The MID proposal does not reflect the FERC guidance provided in the Final Order for the 2001 ISO GMC. This guidance was that a demand charge assessed to the current "control area services" GMC component would appropriately resolve issues of the assessment of charges to all BTM load. There is no demand charge in the MID GMC proposal on any of MID's functions, therefore it does not reflect the Final Order guidance.

In summary, SCE believes that the MID proposal over-allocates costs to the voluntary functions of the ISO at the expense of the mandatory functions of the ISO, improperly sets a two-tiered rate structure for its Resolving Energy Imbalances function, does not reflect the guidance of the recent FERC Final Order concerning the use of demand charges, and does not properly define "power withdrawals", the billing determinant for its Managing Transmission Flows function, so that it will be determined on a comparable basis for all SCs.

SCE COMMENTS ON CDWR GMC PROPOSAL

The California Department of Water Resources has proposed that the ISO proposal be adopted, with the exception that the billing determinant for the Core Reliability Services component in the ISO Staff's proposal should be a "Coincident Peak" (CP") demand rather than a "Non-Coincident Peak" ("NCP") demand. SCE disagrees with the CDWR proposal.

NCP is the appropriate measure of demand for the assessment of the CRS component. This component is based on the "non-scalable" activities that the ISO incurs in providing its "Grid Reliability Services". As such, these are activities that are in place and available 24 hours a day, every day of the year. It is appropriate to charge for these costs on the basis of a measure of the "size" of a customer, and NCP is a good measure of that. If the billing determinant were to be CP rather than NCP, a large customer that just happened to use most of its energy off-peak (such as CDWR) would escape paying its fair share of these costs.

Barkovich k Yap, Inc.

Comments on Criticisms to ISO Grid Management Charge Proposal

ISO Finance Committee
July 24, 2003

Barkovich k Yap, Inc.

Criticisms of ISO Proposal

- Functionalization of Services
- Choice of Billing Determinants
- Other Issues

Functionalization of Services (MID)

- Core Reliability
- Settlements, Metering and Client Relations
- Forward Scheduling

Barkovich k Yap, Inc.

Functionalization of Services (MID)

- The CAISO's primary responsibility is to be a control area operator
  - Balancing and transmission flows are done to achieve reliability, not the reverse
- The allocation of some SCMR revenue to other categories was done only to mitigate bill impacts
  - Effort was designed to recover with related costs, not arbitrarily

Barkovich k Yap, Inc.

Functionalization of Services (cont)

- MID has misunderstood scheduling service
  - Same work to process a fixed schedule as one that varies each hour; each hour's schedule is analyzed and processed separately

Barkovich k Yap, Inc.

Billing Determinant Issues

- Coincident (12 CP) vs. Non-coincident peak (12 NCP) (CDWR)
- Definition of load
  - Net of distribution generation/load (SCE)
  - Consistency with FERC Opinion No. 463 (CAC/EPUC, MID, SCE)
- Definition of exports (SCE)

Barkovich k Yap, Inc.

12CP vs 12 NCP (CDWR)

- FERC's use of 12CP is for transmission, not CRS
- CRS is not transmission, but core reliability services provided on a 24/7 basis
- There is no coincident peak aspect of continuous services
- Planning is a small part of CRS

Barkovich k Yap, Inc.

Definition of Load

- Despite several parties' (CAC/EPUC, MID, SCE) claims, Order 463 is not clear regarding behind the meter load
- SCE creates a new definition of behind the meter load that reflects their unique interpretation of Order 463
- SCE fails to support its proposed Mojave exemption with any cost justification

Barkovich k Yap, Inc.

Other Issues

- More analysis of bill impacts (CAC/EPUC)
- Review of data (CAC/EPUC)

Board of Governors 7/24/2003 **2004 GMC Rate Structure**

MOVED, that Board adopts of the ISO proposal for the 2004 GMC Rate Structure, with active consideration given to inclusion of the modification contained in the Edison proposal regarding the "net vs. gross" issue, providing for the GMC to be recovered through the service categories and billing determinants as set forth in the ISO's presentation to the Committee on July 17, subject to a report from ISO staff within three weeks analyzing the impact of the Edison proposal and staff proposal of the "diversified demand factors" concerning the "gross vs. net" issue.

Moved: Florio Second: Gage

Finance Committee Action: **Passed** Vote Count: **2-0-0**	
Florio	Y
Gage	Y

Moved: Gage Second: Florio

Board Action: **Passed** Vote Count: **4-0-0**	
Florio	Y
Gage	Y
Guardino	Y
Kahn	Y

Attachment 107 Finance Committee Board vote.txt

From: Arikawa, Ben
Sent: Thursday, July 24, 2003 3:24 PM
To: GMC WG
Subject: Finance Committee/ Board vote

The Finance Committee and Board discussion on GMC rate design resulted

in the motion and vote chronicled here:

http://www.caiso.com/docs/09003a6080/24/ba/09003a608024ba70.pdf

The ISO will require additional information in order to respond to the

Board's direction. The ISO would like to have a conference call to discuss the Board's direction and what data will be required to fully respond to the Board. We propose to have this conference call on the morning of Tuesday, July 29. Please let us know if the morning of thi
s
date works for you .

Ben Arikawa
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California Independent
System Operator

2004 GMC Rate Structure Project
Tuesday, July 29, 2003
Conference call
9:00 a.m. to 10:00 a.m.

DRAFT Notes

The meeting began with a brief description of the ISO Board resolution from the July 24th meeting. The ISO Board had adopted the ISO staff proposal, but added the condition that active consideration be given to Edison's proposed modification regarding net load. ISO staff was directed to report back to the Board within three weeks with impact analysis of "gross vs. net," including discussion of the Edison proposal and the potential use of "diversified demand factors." As part of this report, ISO staff would also look into the effect of using Edison's proposed net load on entities other than the investor owned utilities, such as Metered SubSystems and other municipal utilities.

There was some confusion over the exact definition of net load used by Edison. PG&E asked if Qualifying Facilities connected at distribution level voltages could be netted. According to Edison, they could be. MID commented that it would continue to use the definition of net load from the existing rights working group and that this definition was not consistent with SCE's proposal. MID explained that this definition netted flows at their meter at Westley.

SDG&E pointed out that a method that could be consistently applied on a system-wide basis was needed. Sharon Firooz asked if any of the methods could be applicable to everyone.

Edison began a description of its methodology. Generation (QF or utility retained) not connected to ISO controlled transmission, scheduled by Edison and located on its distribution system was netted with load. Starting with the Wholesale Distribution Access Tariff (WDAT), Edison looked at generation connected at distribution level. Any QFs radially connected (directly connected to high voltage transmission) was excluded. The remaining generation was netted against UDC load submitted to the ISO.

CAC asked for clarification. Was Edison trying to look at what generation could be placed on the ISO controlled grid? After some discussion, Edison agreed that the starting point was net control area load from which some additional amount would be removed due to additional "netting" of the type described above.

SDG&E asked about the situation with distributed generation if load was greater than generation. David Cohen asked for an example. The CPUC asked how this related to utility retained generation (URG).

The ISO pointed out that it was necessary to have consistent application of whatever method was used. The ISO asked that Edison provide a write-up of the methodology for everyone to review. Then all affected parties could work on a common language for consistent treatment across the control area. The ISO asked if Edison would be available for a conference call. Edison agreed to have a written document to the group by Wednesday.

David Cohen offered that we could use the existing billing determinants from the GMC project as a starting point and apply modifications to that using Edison's estimates. He asked if the ISO build up the needed information using individual SC ID related data. The ISO pointed out that additional clarification was needed, as Edison was not the only affected party.

MID argued that it was not willing to accept the Edison proposal as resolving all behind the meter issues and that it was premature to argue this at this time. MID also pointed out that Edison's interpretation was new and not part of the record in the 2001 GMC proceeding. Edison argued that it was. The ISO asked Edison to add cites to its write-up pointing to the record in the Order.

SDG&E asked the ISO if it had the data. The ISO does not have the data, but would be issuing an information request for data in the next day or so.

Edison stated that the netting calculation would be redone every year along with its filing of the WDAT.

We agreed to have a conference call Friday morning to review Edison's method, potential methods for consistent treatment across multiple entities and questions posed by the ISO and other parties.

California ISO

2004 GMC Rate Structure Project

Contact List for July 29, 2003 conference call

	Last Name	First	Company	Telephone	E-mail Address	phone
1	Arikawa	Ben	ISO	(916) 608-5958	barikawa@caiso.com	x
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5	Hansen	Bert	SCE	(626) 302-3649	berton.hansen@sce.com	x
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9	Lyon	Deane	ISO	(916) 351-2428	dlyon@caiso.com	x
10	McGuffin	Mike	ISO	(916) 608-5753	mmcguffin@caiso.com	x
11	Morrison	Stephen	ISO	(916) 608-7143	smorrison@caiso.com	x
12	Neal	Sean	MID			x
13	Paradise	Theodore	ISO			x
14	Pritchard	Jan	MID	(209) 526-7490	janp@mid.org	x
15	Regan	William	ISO	(916) 351-4450	wregan@caiso.com	x
16	Ross	James	CAC	(626) 530-9544	jimross@r-c-s-inc.com	x
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19	Slaton	Jeffery	EOB	(916) 322-8601	jslaton@eob.ca.gov	x
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24	Yap	Catherine	Barkovich and Yap			x

ISO 2004 Rate Structure Project
Confidentiality Agreement Register
July 30, 2003

Entity Signing Confidentiality Agreement	Personnel Signing Non-Disclosure Certificates
Southern California Edison	James Cuillier Bert Hansen Jennifer Key Mark Minick Neil Shockey Timothy B. Still
Pacific Gas and Electric Company	Peter Bray Dale Yakin Erik Urias Menzel Robert Kargoll
Modesto Irrigation District	Jan Pritchard Sean Neal Ross Hemphill Laurence Kirsch Michael Postar Blagoy Borissov Perry M. Kreamer Dale J. Bosowski Gerrard N. Stillwagon
Electricity Oversight Board	Patrick Alessandr Tony Lam Brett Franklin Lisa Wolfe Raymond G. Olsson Jeffrey B. Slaton
California Department of Water Resources	Harrison Call Jr. Nancy W. Kirkless Jingchao Mi Michael Werner Gourang Anil Wakade Cheri Caruth Elisa J. Grammer Peter C. Kissel Lee Terry David Sandino Edna Walz David Bonaly

Cogeneration Association of California/Energy Producers and Users Coalition	Rod Aoki Raymond D. Bliven Donald W. Schoenbeck James A. Ross
Transmission Agency of Northern California	David B. Cohen Bryan W. Griess
Northern California Power Agency	James Takehara
Turlock Irrigation District	Michael T. Brommer James M. Farrar
Energy Management Services	Carolyn M. Kehrein
Western Area Power Administration	Michael D. Ryan
California Municipal Utilities Association	Kevin E. Smith
Independent Energy Producers	Katie Kaplan
Sacramento Municipal Utility District	W. Shannon Black Julie Hall Mark Alberter Brian Jobson
Mirant	Steven A. Huhman Philip Auclair
San Diego Gas & Electric	Sharon Firooz Raulin R. Farinas
City of Anaheim P.U.D.	Charles Guss Mark Frazee Lucina Lea Moses K. S. Noller
City of Riverside	Donna Stevener Gary Nolff Lee Anne Uhler Robert Delgado Herman Leung

California Independent
System Operator

2004 GMC Rate Structure Project
Friday, August 1, 2003
Conference call
9:30 a.m. to 11:30 a.m.

Notes

Prior to the conference call, Edison had distributed a written outline of its netting methodology, the calculation in an Excel spreadsheet, and a list of citations from the 2001 GMC proceeding showing where Edison had brought up this concept of netting. Bert Hansen began with a brief description of the Edison method. MID asked a number of clarifying questions.

Edison pointed out that it did not simply net out all its internal generation with distribution load. They stated that only load associated with distribution-connected generation. Edison mentioned that they did not net out the generation from their Big Creek hydroelectric facilities.

There were a number of additional questions on the Edison methodology from PG&E and SDG&E. PG&E questioned that if there were more load than generation, then all generation would be netted and if there were more generation than load, only the excess load is subject to charges. SDG&E asked if the starting point were "gross" or net and if behind the meter load of QFs were included. SCE responded that the starting point was UDC bundled load reported to the ISO and that no behind the meter load of QFs was included.

David Cohen asked if the starting point was net control area load and that Edison's suggested 6.6 percent load served by distribution generation should be subtracted from that. SCE responded that it would be 6.6 percent off of UDC load submitted to the ISO. This brought the question to the ISO: would UDC load submitted to the ISO be best represented by net control area load? The ISO replied that this was probably the case, though it was still a little unclear on the Edison concept.

MID asked why Edison looked at the time of the ISO's coincident peak rather than Edison's non-coincident peak and why this was used to approximate energy. Edison mentioned that there might be some inconsistency.

PG&E asked what constituted transmission level in Edison's proposal. Edison responded that it could go down to 115 kV, but that the defining factor was not voltage, but whether or not it was ISO controlled. This started a long discussion on the voltage levels of the various lines that were turned over to ISO control.

The CPUC and MID asked if Mohave transmission were included in the 6.6 percent that would be netted for Edison under their own proposal. Edison replied that it was not. Mohave was connected at 500 kV and was not on the list of generation on Edison's Wholesale Distribution Access Tariff (WDAT).

The mention of the WDAT brought up the fact that the WDAT filed by PG&E was different in structure than Edison's. PG&E's WDAT did not include QFs, while Edison's did. SDG&E's WDAT does not include QFs, was filed a number of years ago and is not updated annually.

There were a few more questions about QFs, which led to Edison giving an example of how QF generation might be netted against load.

PG&E brought up some of the practical difficulties for PG&E of quantifying the distribution level generation to be netted. It had ISO controlled lines going down to 60 kV and a WDAT structured differently than Edison. PG&E also mentioned that accounting for direct access load would also be a problem. Edison pointed out that it excluded all direct access load.

David Cohen asked about the ISO's 2001 GMC testimony provided by Jim Price and whether that data would be useful. The ISO mentioned that Jim Price's testimony only went to standby load and did not address ISO control of transmission lines. There was some discussion of this, but nothing conclusive.

PG&E mentioned that it would be easier to separate according to voltages than by ISO control. This led to an additional discussion of the voltage levels of the various lines that were ISO controlled.

The CPUC asked if the ISO were going to address the question of the diversity factor as requested by the ISO Board. The ISO pointed out that it had done some preliminary work on this in late May and that this work had been distributed to the GMC WG. The ISO would resend this information out after the conference call.

There was a long discussion of whether any particular proposal was consistent with FERC Opinion No. 463.

The ISO asked if the municipals thought that they would qualify for this netting treatment. MID pointed out that it was quite possible that they would, given that many had internal generation. Edison segregated SCs into two groups: those with bottoms up metering (IOUs) and those with ISO meters at the citygate. Those with ISO meters at the citygate would already be netted. Edison also stated that consistency required that their method apply equally to all entities.

The ISO asked why Edison chose to look at the hour of the system peak to estimate the proportion of load that would be netted and offered that it would be more consistent if the proportion be calculated on non-coincident peak for CRS and on energy across all hours for ETS. Edison stated that the data were available for this calculation.

CDWR asked Edison a series of questions about the number of distributed generators and the number of distribution circuits.

The meeting ended with some questions to the ISO. The CPUC asked what charges were currently gross, what entities were assessed on gross and how the ISO's new charges compared on the issue of gross vs. net. The ISO responded that it would address these questions separately. SDG&E asked if the ISO had a guess as to the overall impact of the Edison's netting methodology on the billing determinant. The ISO did not have the data required for this analysis.

The next conference call was set for 1:30 August 6. In the interim, the ISO would provide a copy of the spreadsheet showing the diversity factors applied to standby load and a copy of the information request to GMC WG concerning generation units and their level of connection. The ISO would also try to clarify questions the CPUC had about the discussion at the Finance Committee meeting on July 24th.

Agenda
2004 GMC Rate Structure Project
Conference Call
Wednesday, August 6, 2003
1:30 p.m. to 3:00 p.m.
Conference Call-in #1-888-788-6681 Passcode: 98563

1. Introductions/roll call
2. Discussion of ISO gross and net load
3. Discussion of diversification factor
4. Discussion of Edison proposal (continued)
5. Discussion of ISO information request

Notes to the conference call and a list of parties on the call follow:

Notes

The meeting began with SDG&E asking MID which of its two options, A or B, were chosen as the preferred method. MID had chosen option B, which did not include a demand charge on Managing Transmission Imbalances.

The ISO described the Board directives from the July 24th Board meeting. The exact timing of the distribution of the ISO report to the Board and the Board or Finance Committee was uncertain, though August 15th had been mentioned as a possible day.

The ISO had distributed a response to some questions that Karen Shea (CPUC) had asked on the August 1st conference call. The ISO attempted to briefly summarize the response, as it was believed that other parties might also have had similar questions. The CPUC pointed out that it was incumbent on the ISO to estimate behind the meter load of governmental entities as a matter of consistency.

There was a long discussion on what method the ISO currently employs in estimation of gross load and what the ISO proposes to do under its proposed rate structure. This discussion also included a recounting of the FERC Opinion N. 463.

At this point, PG&E pointed out that the group was straying from the subject of the call. PG&E asked some clarifying questions about the information request that the ISO sent out on August 1st. It was decided that question 1, definition of the distribution system, was not relevant as the Edison proposal used ISO control as the "bright-line" test. PG&E said that there was some confusion over how to implement the Edison method.

SDG&E pointed out that it might not have the information at the bus necessary to net load at individual bus. SDG&E suggested that generation be netted against load at the bus level, not the individual bus, so long as there was sufficient distribution level load. They argued that without meters, one could not determine the flows and that the simplest method was to assume that 100 percent of the generation was consumed at the bus.

CDWR added that it was important to know how much distribution level load is netted.

CMUA asked if PG&E had done a more refined estimate of its "grid demand." PG&E had done very preliminary work and the range of estimates was 3 to 9 percent. David Cohen asked why PG&E had so much behind the meter load now that most of the Interconnection Agreements had expired. PG&E did not have that information at this time.

Edison explained that only generation owned by Edison or under contract to Edison could be used to net against load. A SC's generation sold directly onto the grid could not be used.

CMUA asked how this information could be verified. Edison replied that all the information that it used was of "settlement quality," and could be verified with information that the ISO already had. Some of the information should be in the ISO's power flow model. All SCs should provide data that the ISO could verify.

SDG&E brought up the issue of confidentiality of certain QF data. They were concerned that they were not allowed to reveal individual account data. Neither PG&E nor Edison were as concerned as SDG&E on this point.

There was some concern over the level of detail needed to respond to the ISO's information request. The ISO stated that there were two issues. The first was providing information for purposes of the report. This information need not be as detailed as specified in the information request given that only a few days remained before the information was due to the ISO. The second was a longer term issue of verifiability of the information if the Board chose the Edison definition of "grid demand."

There was discussion of what information was needed from the municipal utilities. The Southern California municipals typically had remote generation so that they would not be able to "net" this generation with local load. CMUA asked if the MSS could net its internal generation against load. It was pointed out that to the extent that the generation was behind an ISO meter and the load was behind the same meter, then netting could be done. However, if the generation exceeded that load, the excess generation could not be used to net load beyond the "citygate." This raised the issue of the consistency of Edison's proposal with the MSS agreements.

At the end of the conference call, the CPUC again brought up the issue of estimation of behind the meter load of unmetered governmental entities. The CPUC stated that it was significant and material and that the ISO needed to properly frame this issue for the Board.

A next conference call was not scheduled.

California ISO

2004 GMC Rate Structure Project

Contact List for August 6, 2003 conference call

Last Name	First	Company	Telephone	E-mail Address
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Firooz	Sharon	SDG&E	(858) 650-6158	sfirooz@semprautilities.com
Guss	Charles	Anaheim		
Hansen	Bert	SCE	(626) 302-3649	berton.hansen@sce.com
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Paradise	Theodore	ISO		
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Shockey	Neil	SCE		
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Withrow	David	ISO	(916) 608-7134	dwithrow@caiso.com
Yakin	Dale	PG&E	(415) 973-1752	dgy4@pge.com

CALIFORNIA ISO

California Independent
System Operator

ATTACHMENT

Memorandum

Exh. No. ISO-367, Page 1 of 1

To: ISO Board of Governors

From: Bill Regan, Chief Financial Officer

Phil Leiber, Treasurer and Director of Financial Planning

Ben Arikawa, Senior Financial Analyst

Cc: ISO Officers

Date: August 22, 2003

Re: Report on GMC Issues Raised by Board on July 24, 2003

This memorandum is for information only.

On July 24, 2003, as part of the resolution adopting the ISO rate proposal, the Board of Governors asked ISO Staff to examine and report on the "gross vs. net" issue. In particular, the Board directed ISO Staff to study the impacts of adopting the Southern California Edison ("SCE") proposal for "grid demand" and the use of diversified demand factors as part of the ISO's final rate proposal for 2004. Attached is a report addressing these two issues as requested by the Board.

We do not recommend that the Board adopt the Edison proposed definition of "grid demand." This definition of what constitutes load on the ISO grid is new and goes beyond what other parties with behind-the-meter load have argued. It has not been thoroughly vetted in the stakeholder process. We find that there will be significant difficulties in implementation, as described in our report.

We recommend a modification to the 2004 rate proposal for the billing determinant of the "Core Reliability Services" category of the Grid Management Charge (GMC). This modification would eliminate assessment of the Core Reliability Services for behind-the-meter standby load met with its own internal generation. We propose this change in light of recent decisions by the Federal Energy Regulatory Commission (FERC) in the 2001 GMC case and the QF PGA case. While the QF PGA case does not specifically address ISO administrative charges, it provides an indication of how FERC would likely decide an assessment of GMC to QF "behind-the-meter" load if the matter were litigated. We do not propose to extend this treatment to municipal utilities in the Control Area with behind-the-meter generation and load, as they represent diversified load and are not similarly situated. As we are no longer proposing to assess GMC to QF "behind-the-meter" load, we no longer need to consider the appropriateness of applying a diversified demand factor to this load (which would have reduced the level of the assessment of GMC on a gross basis, but still resulted in higher charges than the currently proposed "net" approach.)

If the Board concurs with this recommendation, these changes can be incorporated into ISO's rate filing and adopted with the budget at the October 23, 2003 meeting.

CALIFORNIA ISO

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System Operator

2004 GMC Rate Structure Project

Response to Board Inquiries on Potential Changes to Billing Determinants

August 22, 2003
(Revised September 10, 2003)

Authored by:

Ben Arikawa
Debi Le Vine
Phil Leiber
Stephen Morrison

Table of Contents

1. Introduction

The ISO Staff and stakeholders have undertaken an extensive process over the past year to evaluate issues and concerns with the existing Grid Management Charge ("GMC") design, develop and review three specific proposals, and evaluate the impact of each proposal on individual Market Participants. On July 17, 2003, all three proposals were presented to the Finance Committee and on July 24, the Board voted to adopt the ISO Staff rate design methodology for the GMC to be effective January 1, 2004. In adopting the proposal, the Board left open the possibility of making modifications to the proposed billing determinants[1]. Specifically, the Board directed ISO Staff to study the impacts of adopting the Southern California Edison ("SCE") proposal for "grid demand" and the use of diversified demand factors as part of the ISO's final rate proposal.

Members of the Board raised concerns about the proper billing determinant for the Core Reliability and Energy and Transmission Services components of the Grid Reliability Services function. Concern was expressed over whether to use "gross" or "net" loads and exports as a billing determinant for these two components of the Grid Reliability Services function of the ISO rate proposal. The Board directed ISO Staff to prepare a report on:

- the implications of Southern California Edison's (SCE's) proposed "net vs. gross" billing determinant;
- the application of diversified demand factors on some resources with respect to the Core Reliability component of the proposal.

On August 12, 2003, the Federal Energy Regulatory Commission (FERC) issued Opinion No. 464, in the "QF-PGA" proceeding (August 12 Order). This opinion addressed certain cost allocation issues related to qualifying facilities ("QFs"). With this development, the Board agreed to a one-week extension for this report to permit an evaluation of this opinion.

In this report, ISO Staff begins by clarifying the terminology used in this discussion, as it may be a source of confusion (Section 2). Next is a discussion of the context and underlying motivations of the ISO rate proposal (Section 3). Then, SCE's proposal is outlined with "grid demand" as a billing determinant for the Grid Reliability Services (Sections 4-6). Subsequently, we discuss the definition and the application of a diversified demand factor on contract load under retail standby tariffs (Section 7). Finally, the implications of the ISO Staff's proposal to make gross metering a compliance issue and not to estimate the behind-the-meter load of municipal utilities for purposes of the recovery of the ISO's annual operating and capital costs is considered (Sections 8-9).

The GMC is assessed on all Market Participants based primarily on their volume of activities in the Control Area and in the ISO's markets. The Grid Reliability Services function encompasses the ISO's core reliability functions provided to all loads in the ISO Control Area.

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[1] MOVED, that Board adopts of the ISO proposal for the 2004 GMC Rate Structure, *with active consideration given to inclusion of the modification contained in the Edison proposal regarding the "net vs. gross " issue*, providing for the GMC to be recovered through the service categories and billing determinants as set forth in the ISO 's presentation to the Committee on July 17, *subject to a report from ISO staff within three weeks analyzing the impact of the Edison proposal and staff proposal of the "diversified demand factors " concerning the "gross vs. net" issue.* [emphasis added]

Under the terms of the August 12 Order, QFs are only required to provide the ISO metering and telemetry at the QF's interconnection to the grid. This point of interconnection results in netting the load and generation (i.e. net metering). With net metering in place, the Order further states that ISO ancillary service related charges shall be allocated based on the net meter quantities. While GMC costs are ISO administrative costs separate from ancillary service costs, the specific directive to net meter these entities necessitates a modification in the ISO position that all entities should meter on a gross basis. For very specific reasons, including a recovery of costs through the standby mechanism and the specific characteristics that allow a plant to qualify as a QF, FERC has directed an exception to the ISO Tariff's gross metering / gross meter data policy for those entities. Given this Order, the ISO will recommend net metering for QFs, and assessment of GMC to QFs on a net basis.

As discussed further below, and given the August 12 Order, with respect to the specific issues the Board has asked staff to address, ISO Management recommends:

- charging the GMC to QF load based on the net meter data (eliminating the need for a diversified demand factor)
- excluding the "grid demand" proposal from SCE (as is demonstrated in Section 4, it is primarily only SCE that benefits from the proposal, and from a conceptual standpoint the ISO provides core reliability service to all load in the Control Area, not just the load directly connected to the ISO Controlled, and GMC allocation should be based on cost causation).

ISO Management also recommends retaining the remaining portions of the proposal as adopted by the Board on July 24, 2003 and will proceed with the preparation of its 2004 GMC filing based on this recommendation and the approach presented to and approved by the Governing Board on July 24, 2003.

2. Terminology

Over the course of the GMC project, it has become clear to both ISO Staff and participants in the 2004 GMC project that there is some confusion over the usage of the terms "net" and "gross." The following is the ISO's definition of these terms, as well as the proposed billing determinants for Core Reliability and Energy and Transmission Services and SCE's "grid demand."

The original context of "net" versus "gross" was first derived during the start-up discussions in 1996. Since the ISO Tariff references the term "ISO Controlled Grid" and "ISO Control Area", (the first being a subset of the other), the ISO's responsibilities and span of control differ depending upon the action being taken. The ISO is required by State Law and the ISO Tariff to be the Control Area Operator for the ISO Control Area, yet the ISO only has Operational Control over the transmission facilities that have been turned over to it (i.e. the ISO Controlled Grid). The ISO is required to reliably operate the ISO Control Area and serve all the load in it, regardless of the transmission voltage level at which the load is connected. Additionally, the ISO Controlled Grid does not include all of the transmission lines in the ISO Control Area. Thus serving "gross" load means all load in the ISO Control Area, including that of QFs and Governmental Entities. On the other hand, "net" load is the load of all Participating TOs who turned over their transmission to the ISO plus usage by QFs of Governmental Entities who used the ISO Controlled Grid to serve their load.

Net Control Area Load is the sum of metered demand from all loads with meters. Net Control Area Load also includes load behind a generation meter to the extent that it is separately metered and reported to the ISO[2]. It includes the vast majority of load in the ISO Control Area. Notable exceptions are the Modesto Irrigation District (MID) and the Turlock Irrigation District (TID).

Gross Control Area Load is defined as the total Load in the ISO Control Area and is equal to the sum of the metered Demand (i.e. Net Control Area Load) plus an estimate of the behind-the-meter load from QFs under retail standby tariffs and of certain municipal utilities (primarily MID & TID) that do not provide the ISO meter data. The ISO first proposed this estimate in the 2001 GMC and continues to use this approach today. The ISO estimates behind-the-meter load under retail standby tariffs using data supplied by the investor-owned utilities. The ISO assesses Control Area Services on the entire estimated amount of load and bills this to the investor-owned utilities.

The behind-the-meter load of TID and MID is estimated by examination of Western Electricity Coordinating Council load data that was submitted by the utilities. However, for each entity, the ISO subtracts from the WECC load data the amount of metered load data submitted to the ISO and the maximum Existing Contract usage in accordance with agreements with their host utility. The remainder is assessed Control Area Services and billed to the host utility.

Most entities inside the ISO's Control Area that were potentially "part of the debate" on "gross v net" have since changed their relationship with the ISO. *Appendix A* illustrates that the bulk of the northern California Governmental Entities have become part of a Metered Subsystem while

2 In some instances, a meter exists at the boundary of the entity and on each generator internal to the entities service area. Thus load can be calculated by measuring the boundary meter and adding in the generation meter.

most Governmental Entities in southern California have embraced a Utility Distribution Company or Participating Transmission Owner relationship with the ISO. In each of these circumstances these entities now pay the relevant part of the GMC on a gross basis and would continue to pay on a gross basis under the ISO proposed rate structure.

Non-Coincident Peak ("NCP") is the maximum monthly metered hourly load by Scheduling Coordinator ID (SC ID). ISO Staff did not propose to separately estimate behind-the-meter load under retail standby tariffs or of municipal utilities.

Gross Load [3] is used as the billing determinant in the recovery of the transmission Access Charge. Gross Load includes all load of the Participating TO except behind-the-meter QF load. However, each Participating TO is required to credit the revenue received from standby service of all QF behind-the-meter load. The Governmental Entities that are currently not supplying meter data are not Participating TOs and are therefore not subject to the Gross Load requirements in the Access Charge allocation.

Grid Demand is the Net Control Area Load less an estimate of load that is served by an equal amount of generation on the same distribution circuit or on a non-ISO transmission bus[4]. SCE argues that if there is an equivalent amount of load and generation on a distribution bus or circuit, power does not flow onto the ISO Controlled Grid and should not be assessed ISO charges on load.

3. Context of ISO Staff Rate Proposal

In the 2004 ISO rate proposal, ISO Staff proposes to move from a charge based on energy (as was used for the 2001-2003 Control Area Services category) to charges based largely on demand for reliability-related costs. ISO Staff's proposal was the result of a comprehensive re-evaluation of the GMC over the past year. The ISO retained the consulting firm Barkovich & Yap for their considerable ratemaking expertise. Barkovich & Yap guided ISO Staff in reviewing the ISO's current rate methodology in light of basic ratemaking principles, including determining the practical outcomes of various rate designs that address the particular circumstances of the California markets

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3 In the ISO Tariff (Appendix A, Master Definitions), "Gross Load" is used for the purpose of recovery of the transmission Access Charge. It is defined as:

> For the purposes of calculating the transmission Access Charge, Gross Load is all Energy (adjusted for distribution losses) delivered for the supply of Loads directly connected to the transmission facilities or Distribution System of a UDC or MSS, and all Energy provided by a Scheduling Coordinator for the supply of Loads not directly connected to the transmission facilities or Distribution System of a UDC or MSS. Gross Load shall exclude Load with respect to which the Wheeling Access Charge is payable and the portion of the Load of an individual retail customer of a UDC, MSS, or Scheduling Coordinator that is served by a Generating Unit that: (a) is located on the customer's site or provides service to the customers site through arrangements as authorized by Section 218 of the California Public Utilities Code; (b) is a qualifying small power production facility or qualifying cogeneration facility, as those terms are defined in the FERC's regulations implementing Section 201 of the Public Utility Regulatory Policies Act of 1978; and (c) secures Standby Service from a Participating TO under terms approved by a Local Regulatory Authority or FERC, as applicable, or can be curtailed concurrently with an outage of the Generating Unit serving the Load. Gross Load forecasts consistent with the filed TRR will be provided by each Participating TO to the ISO.

4 There are practical distinctions between distribution and non-ISO grid facilities. However, for ease of discussion, we use them interchangeably.

and the ISO. Additionally, the proposal was developed in concert with and in the full review of a broad range of participants.

It is in this context that ISO Staff reviewed the issues surrounding the "Gross v Net" debate that pervaded so much of previous GMC rate cases. Active consideration was given to embracing the calculation of key billing components on a net basis. In particular, ISO Staff reviewed the proposed Grid Reliability Services function ("GRS") and its sub-function of Core Reliability ("CR") to ascertain their suitability for calculation on a "net" basis.

In addition to the considerable difficulties encountered in defining "net," we were convinced that wholesale exclusion of active entities within the Control Area was a fundamentally unfair approach. The ISO had invested significant resources pressing the case that all entities in the ISO Control Area benefit from the Control Area Services provided by the ISO, and should pay for their provision. A number of municipal and governmental (or quasi-governmental) entities had opposed this position in previous GMC cases, but much of this opposition has been resolved. A number of these entities have moved from having limited or no contractual relationship with the ISO to status as Participating Transmission Owners, or Metered Subsystems, or in the case of SMUD left the Control Area entirely. In addition, as only a portion of the proposed Grid Reliability Services is assessed on gross load, the GMC burden is further reduced for entities that would otherwise argue that the GMC should be assessed on a net basis. The ISO also found support for its view that gross billing was appropriate, as the use of Gross Control Area Load had been expressly approved in the Initial Decision of Administrative Law Judge McCartney in the 2001 GMC rate case[5].

In these circumstances, Staff was not persuaded of the merits of a wholesale "net" approach. However, there was recognition of the fact that there can be a 'degree of impact' difference in the provision of Grid Reliability Services functions for certain types of entities based upon a practical analysis of the state of the Control Area. Specifically, Staff looked at the realistic probability that all behind-the-meter standby load would rely upon the ISO Grid at one time and found it to be low. This led Staff to consider Barkovich & Yap's suggestion to incorporate diversification factors to the assessment of standby contract load. Staff determined there was no need for the use of a diversification factor in light of the considerations described above and later due to the outcome of the August 12 Order (leading the ISO to conclude QF behind the meter load should be exempted entirely from the GMC).

4. "Net" Approaches and the SCE Proposed "Grid Demand"

SCE has not been alone in recommending a more "net-based" approach. Assessing GMC on a net basis is a central element of the Modesto Irrigation District ("MID") rate proposal and had been an ongoing concern of the QF community. MID has consistently argued that wholesale load in the Control Area met with internal generation or flows over non-ISO Controlled Grid facilities

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[5] *California Independent System Operator Corp.*, 99 FERC ¶ 63,020 at 65,108-111, 65,120 (2002) ("Initial Decision") Further, in its order issued on May 2, 2003, *California Independent System Operator Corp., et al.*, 103 FERC ¶ 61,114 (2003) ("May 2 Order"), the Commission rejected arguments that facilities not located on the ISO Controlled Grid / located behind a meter should not be allocated portion of the GMC. The Commission further agreed with the ALJ that all entities that benefit from the ISO's control area operator specific services should pay for those services, but appeared to move from a gross load basis for some generation and load located behind a meter, directing that a demand charge should be used in those cases. The scope of the May 2 Order's cut-off between allocating the GMC based on gross load and on a demand charge basis was unclear to several parties – including the ISO – and the order is currently being reconsidered on rehearing.

should not be assessed GMC. The internal generation and flows over non-ISO Controlled Grid facilities would not be part of the calculation of Control Area Load. MID argues that the correct measure of Control Area Load is that load that is served via energy deliveries over the ISO Controlled Grid (i.e. Net Control Area Load).

Similarly, the Cogeneration Association of California and the Energy Producers and Users Coalition ("CAC/EPUC") argues that the correct measure of Control Area Load is one in which there is no estimate of behind-the-meter load under standby tariffs for QFs, *i.e.*, Net Control Area Load. They have argued that their "behind-the-meter" load is met reliably with on-site generation that does not impact the grid, therefore should not incur Control Area function related costs.

However, neither MID nor CAC/EPUC have agreed with SCE that the correct measure of Control Area Load is "grid demand." They have not argued that an SC's distribution level generation be "netted against load". They have not argued that an SC's generation connected at distribution level away from any specific load be netted against that SC's load. SCE's proposed "grid demand" goes further than any traditional discussion of "gross v net" load.

Very late in the GMC stakeholder process, SCE introduced the concept of "grid demand". SCE proposed the netting of load against generation, not only for those entities that have traditionally formed the focus of the "Gross v Net" debate (*i.e.*, QF standby load and municipal utilities), but for a range of other generating units which are connected to the distribution systems (principally utility-owned generation units or QFs on the distribution system). We have attached SCE's proposal with justifications and definitions (as drafted by SCE) as *Appendix B* to this report.

Stakeholders' consideration of the specifics of SCE's "grid demand" proposal has been limited since it has only recently incorporated into the SCE proposal. Prior to the July 24 Board decision, SCE's "grid demand" lacked much definition, which also limited the ability of stakeholders and staff to evaluate the impact of the revised proposal. After the Board decision on July 24th, SCE provided additional definition and clarification on its "grid demand" proposal. ISO Staff held three conference calls with stakeholders, including SCE, to discuss the concept and issued an information request to participants in the GMC project to determine the impact of the "grid demand" proposal. Seven parties responded to the information requested with varying degrees of consistency. The ISO's information request and the detailed information provided by the parties is attached as *Appendix C.*

Given the information received through conference calls and responses to the information request, the summary results are shown in the following table[6]. Of the seven respondents, two (MID and TID) will show no change between Net Control Area Load and "grid demand." Two respondents (PG&E and Riverside) would show a less than one percent reduction between Net Control Area Load and "grid demand." SDG&E would have a small, less than two percent, reduction. Of the seven respondents, Anaheim and SCE would have the largest reductions.

Edison states that its proposed definition of "grid demand" is a logical extension of its previous positions in the 2001 GMC proceeding and is consistent with the findings of the May 2 Order. ISO Staff does not view "grid demand" as part of a logical progression from previous Edison

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[6] Staff caution the readers of this report of the limited comparability of the information shown, given the limited validation of the data performed by the ISO, and differences in understanding of the SCE proposal by the various parties responding to the request for data.

positions or from the portions of the May 2 Order that speak to charging behind-the-meter load, which that order allows on a gross energy basis or on a net demand basis depending on certain factors. ISO Staff believes SCE and other entities will receive comparable and equitable treatment under the ISO's recommended rate design.

Further, if the Edison proposal for "grid demand" is adopted, ISO Staff finds that there will be significant difficulties in implementation. Among the considerations that will need to be addressed are verification of data provided to the ISO, uncertain bill impacts (as not all parties have responded to the ISO information request), a potential incentive to unilaterally reclassify ISO Controlled Grid facilities to non-ISO grid facilities, potential cost-shifting due to the transmission configuration of each Participating TO, and insufficient vetting of the proposal with stakeholders.

Table 1
Summary of Responses to August 1, 2003 ISO Information Request

Respondent	Percent of Metered Load not in "Grid Demand"
1. Modesto Irrigation District	0.00
2. Turlock Irrigation District	0.00
3. City of Riverside	0.17
4. PG&E	0.97
5. SDG&E	1.85
6. City of Anaheim	4.70
7. SCE	6.60

Notes:

1. Modesto Irrigation District did not supply load or generation data. MID considers its "grid demand" to be equal to its New Firm Use but has no objection to the ISO using net control area load plus exports for the purpose of this study.
2. Turlock Irrigation District supplied data on generation for the fourth quarter of 2002. For the purposes of evaluating the SCE proposal for "grid demand," we have assumed that net control area load plus exports properly reflects TID's grid demand.
3. Riverside supplied data for the first six months of 2003.
4. Pacific Gas and Electric supplied data for the period January 2002 through July 2003 for distribution level generation and February 2002 through November 2002 for transmission level generation.
5. San Diego Gas and Electric supplied generation data for June 2002 through July 2003. Due to missing data, only data for June 2002 through May 2003 were used.
6. Anaheim reported 4.7 percent of its generation serving load on non-ISO grid facilities.
7. Southern California Edison previously supplied data for the calculation of load to be netted out for "grid demand." This data covered the calendar year of 2002.

5. Policy Considerations

Staff's review of SCE's proposed "grid demand" definition has identified a number of significant policy considerations.

Using the SCE definition of "grid demand" changes the way in which load is calculated by the ISO. Currently, and prospectively in the ISO GMC rate proposal, load is calculated from meter reads either directly polled by the ISO or submitted to the ISO by the Scheduling Coordinators. SCE's "grid demand" would require a manual adjustment to submitted meter data for each "SC ID".

Such manual adjustments would be based on data that would be difficult for the ISO to validate. The SCE proposal also reverses the move to direct polled metered data, *i.e.*, away from the more contentious practice of relying upon estimates of key billing determinants used in the GMC. From a policy perspective, it makes the GMC assessment process less objective and subject to potential manipulation by Market Participants. From a practical perspective, it would increase the ISO's administrative costs to process manual adjustments and police compliance of the data to ensure that the "grid demand" amount is consistent with the agreed upon definition.

Not surprisingly, the use of "grid demand" will have bill impacts, reducing the bills of some SCs at the expense of others. The data in Table 1, though incomplete, provides some insight into the potential shifts in GMC costs that such a move would entail. SCE has the highest proportion of such load at 6.6% of their total, while only three other entities have any, and at significantly lower proportions, not exceeding 1.85% (SDG&E). Those entities with smaller reductions from Net Control Area Load will see their bills for Grid Reliability Services increase, while those with the larger reductions will see reductions. Because not all SCs have such generation in the same proportion as their overall use of the Grid, cost shifts resulting from this proposal are likely to be opposed by many SCs, potentially increasing the litigation that would ensue if this proposal is adopted.

Despite the availability of some data in Table 1, SCE's proposed "grid demand" would create uncertain impacts on SC bills, if applied consistently across the Control Area. SCs other than those that responded to the ISO's August 1, 2003 information request may have load adjacent to generation connected at distribution level that could be netted. For example, the City of Pasadena has generation within its service territory, which is used to serve its own load.[7] Tracking the outcome of these bill impacts would be dependent upon many factors, including the effect on MSS Agreements. (As noted below, signatories of MSS Agreements may decide to seek changes in their Agreements to incorporate a net approach.) Thus, the uncertainties associated with Edison's proposal have not been fully quantified by the data provided in Table 1.

ISO Grid Operations has voiced concerns about potential detrimental effects of adopting a more "netted" approach. The SCE proposal in particular could create an incentive for the Grid to become sectionalized; *i.e.*, with more generation constructed on lower voltage lines closer to load. This could potentially cause increasing bills on load that relies on more remote generation, and might lead to an ever-increasing incentive to re-classify lines away from ISO control.

6. Implementation Issues

Staff has reviewed the practical difficulties of implementing the SCE "grid demand" proposal.

First, there are difficulties with providing consistent treatment of entities under SCE's proposal. To establish the ISO Controlled Grid in 1997, each investor-owned utility ("IOU") provided lists of transmission facilities that it proposed to transfer to ISO Operational Control, and sub-transmission over which it proposed to retain operational control. The latter are what SCE refers to as "non-ISO grid". The voltage level dividing line between ISO and IOU (or other

[7] Unfortunately, the City of Pasadena has not been a participant in the GMC project and has not responded to the August 1, 2003 information request.

Participating TO-controlled) transmission facilities varies significantly among the utilities mainly due to the functionality of the facilities and each entity's transmission expansion plan. This complicates the process of determining which generation facilities might qualify as distribution connected. Furthermore, this division would impact all other utilities choosing to join the ISO. The Pacific Gas and Electric Company (PG&E), SCE and San Diego Gas & Electric Company (SDG&E) systems were planned using different grid planning philosophies. SCE radialized their subtransmission system from their transmission system in most cases, while PG&E and SDG&E run their transmission and subtransmission systems in parallel. What may be clearly transmission level for SCE may not be for PG&E and SDG&E. On SCE's system, transmission voltage is typically greater than 115 kV. On the PG&E and SDG&E, transmission voltage could go down to 69 kV. SCE makes no proposal as to how these differences might be reconciled and there seems no fair method for otherwise achieving a consistent methodology.

Additionally, ISO Grid Operations is concerned that the SCE "grid demand" concept gives rise to particular electrical problems, not associated with the net concepts of MID or pertaining to the QFs. In the SCE case, unless the generation (and load that is being served by it) is at the end of a metered, radial distribution line, it would be difficult to determine if the generation (that is receiving the netting) is actually serving the netted Load (*i.e.*, the electrical current flow may not serve nearby load, an electron flows based on the path of least resistance). The load may be served by other generation passing through the distribution system, or from additional generation that the IOU does not have under contract but is in the area.

If implemented as SCE proposes, the netting calculation would be a percentage reduction in the NCP demand and the Controlled Grid Load plus exports. This percentage would be based on the distribution level generation and load at the monthly ISO system peak hour for a previous twelve-month period. Whatever method is chosen, it will have an uncertain impact on the NCP used as a billing determinant for Core Reliability Services. As the peaks at the various distribution busses are not necessarily coincident with the Scheduling Coordinator's total NCP, the "netting" will increase the NCP and the uncertainty of the ISO's forecast of NCP.

The shift of a number of entities to Metered Subsystem (MSS) status, or a participant in one, has been memorialized in both the MSS Agreements and in the ISO Tariff. The MSS entities have agreed to pay GMC on the basis set forth in the Tariff, which at the time the agreements were established, was gross. This commitment was one of the key objectives of the ISO in negotiating the MSS Agreements. While the MSS entities are not likely to oppose a move to net billing, this will increase costs to other SCs, and in the view of ISO Staff, will result in these entities contributing a less than equitable portion of the costs of maintaining the control area. Additionally, this would be inconsistent with cost causation principles that are specifically addressed in the MSS Agreement.

In light of the direction given by the Judge McCartney in the 2001 GMC rate case that the ISO undertake its comprehensive review of the GMC methodology with full stakeholder involvement, as well as the commitments agreed to in the GMC Settlement Agreement of 2002, ISO Staff has sought to ensure that the stakeholder process for this project was inclusive and meaningful. Therefore, it would be appropriate that any revisions to what the ISO ultimately proposes in its filing for a 2004 GMC rate, absent a FERC Order, should have been subject to the same rigorous and open review as the bulk of the ISO Staff Proposal.

The SCE proposal has not been subject to such Stakeholder review. The concepts were not developed in the full view of all stakeholders, and appeared for the first time only near the end of the stakeholder process While the stakeholders did learn more of the proposal in the ISO's efforts to develop this report, this was an accelerated process that left significant questions as to the effects of the proposal and insufficient time to obtain the data needed to evaluate the proposal. The "net" components of the MID proposal, on the other hand, have been developed as part of the same process as the ISO Staff proposal over the past year. While it has not formed part of a separate GMC rate methodology, the position of the proponents of QF netting is similarly well established, by record in prior cases, as well as by re-iteration in the GMC project. Staff is, therefore, reluctant to recommend that the Board consider any revisions to the ISO rate proposal that have not been reviewed in the context of the comprehensive Stakeholder Process established as a result of judicial direction and settlement.

7. Diversified Demand Factor Analysis

The Board motion also directed Staff to consider the use of "diversified" demand factors for certain customers. Diversified demand factors are used as an adjustment when considering the load of a particular class of customers rather than the entirety of customers of a utility. In this instance, the diversified demand factor would be applied as an adjustment to the contract capacity under retail standby tariffs. This adjustment would result in a reduction in their load on the system to account for the fact that there is considerable variety in their operation and that sum of their individual peak demands would exceed the actual class peak usage of the grid.

In the 2001 GMC proceeding, the ISO obtained aggregate data on standby tariff agreements of the IOUs. This data contained contract demand figures representing the maximum load that the standby customer can place upon the utility's system in the event of an outage. At first blush, the contract demand may seem to be the counterpart to the NCP for SCs, and, on that basis the ISO should assess GMC on their full contract demand. However, the contract demand overstates the impact of standby load on the NCP. While these customers are generators, they are, for the most part also relatively small, numerous, and are attached to the utility distribution or sub-transmission systems, not directly to the ISO Controlled Grid. Furthermore, it is extremely unlikely that all of the standby customers would experience an outage simultaneously[8].

Standby customers would be assessed in groups and a diversity factor be applied to the total contract demand. A diversity factor essentially provides an expected value of the non-coincident demands that standby customers would likely place on the utility's (hence the ISO's) system. To the extent possible, the diversity factor should be based upon metered standby data, both coincident and non-coincident. The non-coincident loads are the correct measure for the probability (expected value) that the customer could impose load on the utility's system. However, to the extent that standby customers impose loads during the utility's peak hour each month (coincident demands) these loads will already be included in the metered utility data. Therefore, the diversity factor should be reduced to remove the coincident loads and avoid any double counting. Based upon 1998-99 metered data for PG&E's standby customers, it is estimated that about 3% of contract demand

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8 The WECC requires that operating reserves be provided for 5% to 7% of all firm load to provide additional resources in the event of an unplanned outage.

levels are coincident while about 16% are non-coincident. Hence, the correct diversity factor is about 13%; this would be applied against the total standby contract demand levels[9].

Using the data provided by the IOUs in 2000 and submitted by the ISO in its 2001 GMC rate filing, application of the diversity factor results in behind-the-meter standby load being assessed less than $500,000 annually. This amount is considerably less than the current assessment to the IOUs for behind-the-meter retail load. Table 2 shows the current Control Area Services assessment and the potential future assessment of Core Reliability Services to the IOUs for behind-the-meter retail load. This amount is likely to be lower given that some of these parties included in the data are no longer under standby tariffs.

Table 2
Comparison of GMC Assessments on Retail Behind-the-Meter Load
Control Area Services (CAS) vs. Core Reliability Services (CRS)

	CAS at $0.57 per MWh	CRS at $175 per MW-month NCP using 13 % diversified demand factor	Difference
PG&E	$1.22 million	$0.18 million	($1.05 million)
SCE	$1.85 million	$0.20 million	($1.65 million)
SDG&E	$0.26 million	$0.03 million	($0.23 million)

Notes:
1. The current methodology of assessing Control Area Services to retail behind-the-meter load is laid out in the testimony of Jim Price of ISO Staff in the 2001 GMC rate filing.
2. The assessment of CRS uses the contract capacity data provided in the 2001 GMC rate filing and applies a diversity factor of 13 percent.
3. These results and the underlying data were provided to participants in the GMC project.

8. New Circumstances

Since formulation of the original ISO Staff Proposal, we have noted several additional relevant events. The May 2 Order was issued confirming most of Judge McCartney's favorable Initial Decision in the 2001 GMC rate case but adding to other parts, principally a mitigation of the effect of applying full Gross Control Area Load calculations on certain customer's GMC assessments[10]. Just prior to the original scheduled release of this report, FERC issued the August 12 Order addressing whether QF metering, telemetry, scheduling, and A/S procurement should be provided to the ISO on a net or gross basis. The August 12 Order affirmed a 2001 ALJ Initial Decision on those matters in favor of a "net basis". These factors, taken together with the conclusions of Staff's investigations into the details of various "net" considerations, have led to the recommendations to only assess standby load to the extent that its generation is insufficient to meet its load, thus contributing to an SC's monthly non-coincident peak demand.

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9 ISO Staff, its consultants, Barkovich & Yap, and CAC/EPUC has had several conference calls to discuss diversity factors and their application. Prior to the August 12 Order, we agreed on principles, but not on the actual quantification. The data referred to here was supplied by CAC/EPUC.

10 May 2 Order at P 27: "As we have discussed above, however, behind-the-meter customers, wholesale or retail, with a generator that has a capacity factor of 50 percent or more, are to be allocated CAS costs based on their highest monthly demand. This exception applies to whether the behind-the-meter generation is wholesale or retail."

However, we remain unchanged in our view that municipal utility behind-the-meter load should be fully metered and assessed on this gross metered basis. Unlike a cogenerator under a retail standby tariff, a municipal utility has diversified load and, thus, is not similarly situated to retail standby load. The ISO has consistently argued that the ISO provides essential services to all entities in its Control Area and that all entities derive some benefit by being in the Control Area. The FERC affirmed this position in both the 2001 GMC rate case and the separate TID & MID v ISO complaint case on discrimination by the ISO.[11] Netting of municipal or governmental entities behind-the-meter load (though effectively only for two municipal entities), therefore, remains inappropriate.[12]

9. Conclusion & Recommendation

The ISO Staff Proposal was formulated with perhaps the most comprehensive stakeholder process yet undertaken by the ISO and we have reviewed a full range of "net considerations" in drawing up these conclusions and making the following recommendations. Despite the extensive stakeholder process, the influence of events outside the immediate sphere of Staff's considerations, and even beyond the stakeholder process, have created a need for a specific revision. The previous recommendation in the ISO Staff Proposal of billing the QF entities (specifically those with Standby Agreements with Utility Distribution Companies) for their share of the Control Area Service functions of the GMC, is now revised. Staff no longer recommends inclusion of that set of entities in the specific 'gross' calculations for the Core Reliability Service functions (which was their only liability for GMC under the original Staff Proposal).

Staff, therefore, recommends a change to the billing determinant for the Core Reliability Services that was previously submitted to the Board. The billing determinant would be metered Control Area Load with no explicit accounting for QF behind-the-meter load. However, given their different situation, we would still require that the municipal utilities adhere to the metering and meter data submission requirements in the ISO Tariff.

Staff believes that this position is one in which the ISO will be able to credibly defend in the October rate filing and through the ensuing proceedings. We believe that the position taken of assessing QF load on a net basis is distinguishable from all other load in the Control Area, which would be assessed on a gross basis (non-coincident peak demand by SC ID).

As discussed above, we also believe that SCE's net-net proposal should not be adopted. Apart from the substantive concerns about the proposal, Staff believes that the lack of adequate stakeholder review of the proposal argues against its adoption.

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11 *Turlock Irrigation District and Modesto Irrigation District vs. California Independent System Operator Corp.*, 100 FERC ¶ 63,016 (2002).

12 Staff recognizes that paragraph 27 and 34 of the May 2 Order may be read as supporting claims that both retail and wholesale load should in limited circumstances be levied GMC on the basis of highest monthly net usage of the grid. However, the ISO and other parties have sought clarification of this Order, and ISO Staff does not believe it would prevent the ISO from assessing the GMC to wholesale entities for 2004 on a gross, non-coincident peak basis.

Appendix A

Status of entities within the California ISO Control Area re Gross -v- Net portion of GMC

Entities Paying Gross (Due to the status of their current legal arrangements with CAISO)	**Entities Refusing to Pay Gross** (Due to the lack of express legal arrangements directly with CAISO)	**Miscellaneous Categories** (Each separately addressed below)
Participating TOs (all also UDCs) Pacific Gas and Electric Company Southern California Edison Company San Diego Gas & Electric Company City of Vernon City of Anaheim City of Azusa City of Banning City of Riverside **<u>UDCs</u>** Pacific Gas and Electric Company Southern California Edison Company San Diego Gas & Electric Company City of Anaheim City of Pasadena **[NOT a PTO]** Lassen Municipal Utility District **[NOT a PTO]** City of Vernon City of Riverside City of Azusa City of Banning City of Hercules (dba Hercules Municipal Utility) **[NOT a PTO]** [Negotiation in Progress: Westside Power Authority] **<u>Metered Subsystems</u> [NOT a PTO]** Northern California Power Agency as aggregator, representing the following NCPA MSS members: (City of) Alameda Power & Telecom City of Biggs City of Gridley City of Healdsburg City of Lodi City of Lompoc City of Palo Alto City of Ukiah Plumas-Sierra Rural Electric Cooperative Port of Oakland (Oakland Airport Service Area only) City of Santa Clara (dba Silicon Valley Power) City of Roseville [Negotiation in Progress: City of Colton] *(N.B. There are other - smaller - NCPA Members not listed here)*	Modesto Irrigation District Turlock Irrigation District (including Merced Irrigation District)	Western Area Power Administration, Sierra Nevada Region [Currently pays via PG&E – considering separate Control Area or MSS/PTO status.] (Includes Tracy Federal Pumps and Cites of Shasta Lake & Redding) **Entities Scheduling Gross under some other status (*e.g.*, ETC via a PTO) *i.e.*, entities that do not Schedule directly with the ISO** California Department of Water Resources The Metropolitan Water District of Southern California East Bay Municipal Utility District (Generation only?) Hetch Hetchy Water & Power (City and County of San Francisco) (Generation only?) TANC (Transmission only) M-S-R Public Power Agency (Generation only?) Central California Power Agency (Generation only?) Southern California Public Power Agency (Generation only?) Oroville/Wyandotte Irrigation District (OWID), Yuba County Water Agency (YCWA), Nevada Irrigation District (NID), Placer County Water Agency (PCWA), Tri-Dam, SID) City of Sunnyvale, County Sanitation District No. 2 of Los Angeles County, El Dorado Irrigation District, Monterey Regional Waste Management District, Riverside County Waste Management District, Utica Power Authority

Appendix B

Documents provided by Southern California Edison

in Support of

Its Grid Demand Proposal

July 30, 2003

DETERMINATION OF COMPARABLE ISO GMC BILLING DETERMINANTS FOR ALL SCHEDULING COORDINATORS

DESCRIPTION OF SCE PROPOSAL

1) THE BOARD MOTION AND SCE'S PROPOSED MODIFICATION

At the July 24 ISO Board Meeting, the ISO Board passed the following Motion:

> MOVED, that Board adopts of (sic) the ISO proposal for the 2004 GMC Rate Structure, with active consideration given to inclusion of the modification contained in the Edison proposal regarding the "net vs. gross" issue, providing for the GMC to be recovered through the service categories and billing determinants as set forth in the ISO's presentation to the Committee on July 17, subject to a report from the ISO staff within three weeks analyzing the impact of the Edison proposal and staff proposal of the "diversified demand factors" concerning the "gross vs. net" issue.

The modification contained in the SCE proposal, as presented to the Finance Committee of the ISO Board on July 17 is that:

> "Comparable billing determinant measurement for the CRS and ETS charges (all behind-the-meter load treated comparably."[1]

As SCE explained in this Finance Committee presentation, in the simple case of a small municipal utility with a single meter located at its city-gate, ISO Grid Demand and ISO Grid Energy is measured by that meter, as adjusted for distribution system losses. But in the case of SCE and some other large distribution utilities, which have multiple distribution lines serving loads from the ISO Grid, ISO Grid Demand and Energy cannot be measured by a single meter. This is because the load for these Scheduling Coordinators is measured in a "bottom's up" manner based on the readings (adjusted for losses) of, in SCE's case, four million plus end-use retail meters. However, SCE has generation located downstream of the ISO interface on distribution which reduces the ISO Grid Demand and Energy of SCE, but is not captured by the bottom's up billing approach. In order to determine SCE's ISO Grid Demand and Energy on a comparable basis to entities that are billed based on their wholesale city-gate meter, an adjustment must be made to SCE's calculated end-use load to reflect any distribution level generation.

[1] See pages 6 and 8 of the "GMC Proposal" of Southern California Edison, presented at the July 17 Finance Committee meeting.

2) SCE'S PROPOSED METHODOLOGY

SCE's proposal for determining the ISO Grid Demand and ISO Grid Energy is:

1) Determine the hour of the ISO's peak load for each month of the prior year.
2) Determine the Scheduling Coordinator's total end-use demand, adjusted for losses to the ISO Grid, for that hour.
3) Determine the distribution level generation of the Scheduling Coordinator during that hour. Only include generation on distribution circuits that have associated load. "Distribution" is defined to be non-ISO Controlled Grid.
4) Sum the Scheduling Coordinator's monthly demands (from 2) and the Scheduling Coordinator's monthly distribution level generation (from 3) to derive annual values for each.
5) Divide the sum of the Scheduling Coordinator's monthly distribution level generation by the sum of the Scheduling Coordinator's monthly demands to derive a "percent reduction factor".
6) For billing the CRS and ETS components of the GMC, the "percent reduction factor" would be applied to both the monthly total demand and total energy for the Scheduling Coordinator, as determined based on the end-use meter data, adjusted for losses.

Attached is a one-page spreadsheet deriving SCE's percent reduction factor for the year 2002. As shown, the percent reduction factor is 6.60%.

To implement the principle that comparable billing determinants be determined for the CRS and ETS components of the GMC, SCE proposes that this percent reduction factor be developed and submitted for approval to the ISO by each Scheduling Coordinator for which the ISO utilizes "bottoms-up" metering. The factor would be submitted annually to the ISO. If no factor is submitted, the ISO shall utilize the bottoms-up metered loads for the GMC billing (adjusted for applicable distribution losses).

SCE POSITION ON COMPARABLE BILLING DETERMINANTS

CITES FROM 2001 GMC CASE

At the GMC call held on July 29, 2003, the ISO requested that SCE provide cites indicating instances where SCE had taken the position that billing determinants should be determined on a comparable basis for all Scheduling Coordinators. SCE has researched the matter and has found the following cites from the record.

CITES TO SCE POSITION

SCE opposed wholesale netting throughout the GMC proceeding. But, to the extent other intervenors proposed wholesale netting, SCE made certain that the record reflected that all customers with wholesale behind-the-meter (BTM) load be treated comparably. First, SCE ensured that the record reflected that the IOUs such as itself had wholesale BTM load:

> [Ms. Key] For example, just as some municipal utilities have generation internal to their distribution systems, you're aware that [IOUs] also have substantial generation internal to their distribution systems as well?
>
> [Dr. Kirsch] And if that results in the power taken off of the ISO grid beyond that, that would reduce the billing determinant applicable to that utility or to that SC.

Tr. 1701. Mr. Minick explained:

> [Mr. Ortman] For that reason, I take it, with regard to a governmental entity like SMUD whose load is partially met by no utilization of the ISO Controlled Grid, both with respect to its behind-the-meter generation as well as a COTP import, you would disregard that fact in its entirety and round up all of GMC, and all of SMUD's gross load. Is that your position?
>
> [Mr. Minick] A. Yes, it is, and the reason for it is Edison has transmission and distribution that hasn't been turned over to the ISO. We have generation on that distribution system that is serving load. That generation that gets put on that and never comes off the ISO grid is very similar, if not identical, to your distribution and transmission system. If you want to get Edison's distribution system from the CAS, I guess we agree.
>
> * * *
>
> I've listened to all the things that your joint interconnection agreement says that SMUD does. Edison does all those,

> and actually more in some cases. We are an interconnected distribution grid to ISO, as you are a transmission and distribution connected grid to the ISO. We are very similarly situated.

Tr. 2211-2212.

> [Ms. Key] Would you agree essentially that the three IOUs in addition to the governmental entities have what is wholesale behind-the-meter load, effectively?
>
> [Ms. Le Vine] A. Yes.
>
> Q. Thus, if there's an exemption, if the control area services charge was based on withdrawals from the ISO control grid, that the total amount of load charged would be reduced both for the IOUs and for the governmental entities?
>
> A. If I understand what you're saying, yes.
>
> Q. . . . If you were measuring how much load users off the ISO control grid -- certainly not all of the IOU load at any given hour uses the ISO control grid?
>
> A. Based on power flows, no.

Tr. 1832-33.

Second, in its Initial Brief (on Issue III.3), SCE explained that Governmental Entity (GE) wholesale BTM load is similarly situated to IOU wholesale BTM load (as opposed to retail BTM load). SCE included the following argument to ensure that all wholesale load be treated the same way. Although SCE did not support netting for either IOU or GE wholesale BTM load, it stressed their similarity:

> A key discrimination issue is whether SCE's and CAC's position on exempting retail BTM load when self-served by on-site generation would result in undue discrimination against GEs' wholesale (internally served) BTM load (Table A, Load/Export Category 4) and/or GEs' wholesale load served over non-ISO Controlled Grid facilities (a subset of Load/Export Category 5). The answer is no. GE loads served by internal generation or over non-ISO Controlled Grid facilities are similarly-situated to IOU wholesale loads served by internal generation, but are not similarly situated to retail BTM loads served by on-site generation. As explained by the ISO, retail and wholesale BTM loads simply are "not the same." Tr. 1466:9-12 (Le

> Vine). When asked whether the ISO should lump together retail and wholesale BTM load when talking about Control Area Services, the ISO explained that the two were "[l]ike apples and oranges." Tr. 1466:20-24.
>
> There may be a "perceived" similarity between retail BTM load served by on-site generation and GE wholesale BTM loads in that the deliveries to such loads do not flow over the ISO Controlled Grid. But, there is a much greater similarity between GE wholesale BTM loads and IOU wholesale loads that similarly are not served through deliveries flowing over ISO Controlled Grid facilities. Several witnesses testified that the three IOUs also have wholesale BTM load (that is, load served by internal IOU generation). It would be unduly discriminatory if GE wholesale loads that are served by deliveries from internal generation not flowing over the ISO Controlled Grid were exempted from the CAS Charge, while comparable IOU wholesale loads were not exempted. Dr. Kirsch admits this and proposes that for both IOUs and GEs that actual power flows be used to determine the extent to which GE and IOU wholesale loads are served by energy flowing over the ISO Controlled Grid. Tr. 1701-1702.

Third, in its Reply Brief on Issue III.E, SCE responded to arguments that certain wholesale customers should receive net treatment due to self-provision by using the argument that such an approach is discriminatory. SCE explained in its Reply Brief how the IOUs also self-provide the services wholesale ETC customers self-provide and that the two are similarly-situated:

> the ETC customers have absolutely no evidence that indicates they are self-providing control area services in a manner different from the entities serving non-ETC loads and exports. The control area service obligations under the IA that SMUD recites (SMUD IB at 19-20) are no different than the obligations that SCE has to the ISO as a PTO, SC, and UDC, which obligations were listed in SCE's Initial Brief at 10 (showing that the ISO Tariff and Transmission Control Agreement (TCA) require the self-provision of the very same control area services that SMUD and TANC claim are self-provided by GEs). SCE is not contesting the fact that ETC customers' self-provision of control area services reduces the cost burden on the ISO, what it is contesting is the notion that such self-provision reduces the cost burden on the ISO to any greater or lesser extent than any other entity serving loads and exports in the ISO control area. SCE agrees that if the ISO had to perform all

the control area service tasks currently self-provided in addition to the Control Area Services it does provide, its costs would be much higher. What the ETC customers have failed to prove is that other utilities do not self-provide all or most control area services in the exact same fashion.

Moreover, by singling out ETC holders as self-providers of control area service, the ETC customers reveal the unduly discriminatory nature of their argument. TANC, for example, argues that assessing the CAS Charge to ETC customers that support the ISO's provision of Control Area Services violates cost causation principles. TANC IB at 26. Nowhere, however, does TANC argue that assessing the CAS Charge to a PTO or IOU or UDC that supports the ISO's provision of Control Area Services violates cost causation principles. SMUD's witness immunized himself against having to testify as to whether or not a UDC self-provides control area services by stating that he had absolutely no knowledge on the subject. A brief skim of the ISO Tariff and TCA, however, reveal that PTOs and UDCs (i.e., non-ETC customers) perform the very same control area services that the ETC customers claim they perform.

In short, under the GEs' proposal, whereby self-providers of control area services pay no CAS Charge, there may well be no entity left to pay the charge at all, as self-provision of such services on a service-area-wide basis is the norm, not the exception.

Finally, to the extent necessary, SCE reargued the above points in its Briefs on Exceptions and Opposing Exceptions.

Line	Month>>	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Annual Total
5	Peak Day/Hour>>	29/HE19	21/HE19	18/HE20	23/HE21	30/HE16	5/HE17	9/HE16	12/HE16	23/HE16	7/HE16	20/HE18	19/HE19	
6														
7	UDC Bundled Load	10,259	9,823	9,871	9,871	11,185	12,548	13,928	13,854	14,880	12,163	10,705	10,705	139,793
8														
9	Distribution Generation (1)	904	692	736	739	730	907	724	832	725	697	699	836	9,220
10														
11	SCE Grid Demand (2)	9,355	9,132	9,135	9,132	10,455	11,642	13,204	13,021	14,155	11,465	10,006	9,869	130,573
12														
13	% reduction (3)													6.60

Notes:

1. Includes those utility retained generation (URG) and SCE QF generating facilities taking service under SCE's FERC WDAT tariff, excluding the amount of this generation radially connected to the ISO Controlled Grid with no associated customer load, and also excluding Big Creek generation.

2. = Line 7 - Line 9.

3. = ((Line 7 - Line 11)/Line 7 * 100).

Appendix C

California ISO

August 1, 2003 Information Request

and Responses

Non-Confidential Responses

August 22, 2003

CALIFORNIA ISO

California Independent
System Operator

California ISO Information Request for GMC Working Group Participants
Please send your responses to Ben Arikawa (barikawa@caiso.com)
by COB August 8, 2003

1. Please provide a definition for your distribution (less than 69kV) and transmission (typically 69kV or greater) systems in your service area, including voltage designation, functionality and other identifying characteristics.
2. Please provide a list of the Generating Units with a nameplate rating of 1 MW or greater that are located within your service area. For each unit, please provide the following information:
   a. Common name of Generating Unit
   b. ISO Resource ID for the Generating Unit
   c. Physical location of Generating Unit (Street name and address or descriptive address as applicable).
   d. ISO Location ID of Unit, if applicable.
   e. Name and voltage designation of transmission or distribution line, substation bus or other apparatus to which plant is directly interconnected (*i.e.*, the voltage level on the high voltage side of the generator step-up transformer).
   f. Is the line identified in the previous question transmission or distribution?
   g. If line identified in the previous question is of distribution voltage level, please identify the transmission line, substation bus or transformer to which the distribution line is first connected.
   h. If equipment identified in (g) above is not an ISO Controlled Grid facility, please identify the ISO Controlled Grid facility to which the Generating Unit is first connected.
   i. Type of Generating Unit, including fuel consumed.
   j. Nameplate rating of Generating Unit.
   k. Number of kWh per month produced by Generating Unit for the previous 12 months, on a monthly basis.
   l. Peak instantaneous MW output of the Generating Unit for previous 12 months, on a monthly basis.
   m. Has the Generator executed a PGA with the ISO?
   n. Does the Generator sell power to you under a Standard Offer Contract?
   o. Does the ISO have telemetry or other metering to allow direct polling of the Generating Unit or is meter data otherwise reported to the ISO?
   p. Is more than one Generating Unit located at the generation site?
   q. What percentage of this Generating Unit's output serves load only in the immediate distribution system?
   r. Please verify that power from this Generating Unit in excess of the percentage identified in the previous question has not been scheduled outside of the immediate area during the last 12 months.

3. Is the load associated with the Generating Unit capable of disconnecting or designed to disconnect simultaneously when the Generating Unit separates from the Grid for other than planned and coordinated outages?

MID's Response
to
The CAISO's Information Request for GMC Working Group Participants

From the inception of the Existing Rights Working Group ("ERWG") to the present, MID has held the consistent position that wholesale "behind-the-meter" treatment applies only to those entities that have the physical capability to balance load and generation at one or more interconnection points with a control area operator. When we speak of "net", we mean net interchange.

MID understands that SCE proposes to expand the definition of "behind-the-meter" load to include "netting" of generation and load that is connected to facilities that SCE has not turned over to the operational control of the CAISO - such as distribution circuits. Because the SCE proposal adds a new category of load and generation that would be eligible for "behind-the-meter" treatment, it is obvious that the ERWG definition alone would not serve to evaluate the SCE proposal.

However, it is clear that the SCE proposal would neither increase nor decrease MID's historical determination of "net" load. For that reason, MID will continue to rely on the same definition of "behind-the-meter" that MID has relied upon since the ERWG.

Therefore, for the limited, non-precedent setting purpose of evaluating the SCE proposal pursuant to the specific request of the CAISO Board of Governors, the CAISO may employ either of the following methodologies in determining the portion of MID's load subject to GMC charges.

1. The CAISO has already determined "Control Area Net Load" using its own estimate of MID's load for the applicable time period. If the CAISO is comfortable with this number, then the CAISO may use this number.

2. The portion of MID's load subject to GMC is that which is served by New Firm Use ("NFU"). MID's NFU is exclusively scheduled by PG&E under the MID/PG&E Interconnection Agreement. If the CAISO has this number, the CAISO may use it for the purposes of this evaluation.

PG&E Response to August 1, 2003 Information Request
Effective Net Load - Calculation Methodology and Results:

The objective of this data request was to determine the amount of generation that was transferred and consumed exclusively over PG&E facilities that are not under ISO control. For analysis of the SCE proposal to subtract generation delivering into non-ISO controlled facilities through non-radial pathways, this generation would be subtracted from gross load to determine an "Effective Net Load" for the service area.

PG&E notes that in compiling this estimate:

1. The determination of generators that do not feed through the ISO grid may not be comparable between PG&E and other utilities given differences in determination of which levels of voltage are included in transmission level.
2. If these data are to be used for assessing charges among utilities, the determination of generators which are included should be prepared on a comparable basis among utilities. The fact that SCE, SDG&E and PG&E have used different criteria for transferring operational control of facilities to the ISO should not result in an undue cost shift of GMC costs to PG&E and SDG&E.
3. Use of a comparable basis for such determination of net load could affect the ISO's calculations and any conclusions derived from them; therefore, PG&E does not agree with use of the methodology proposed by SCE unless adjustments are made to make the generation data comparable.

Process:

1) Compile list of generators within the former PG&E control area.

2) Remove generators without a PPA {do we also remove WAPA and other government owned generation as well?} . Remaining generators are scheduled by PG&E as part of the company's resource portfolio.

3) For those generators identified in #2 as part of the PG&E portfolio, PG&E divided the list into two groups:

a) Distribution-Level Generators with 12 or 21 KV capacity and feeding a distribution-level substation. These substations should be under PG&E control and serve a load.

b) Transmission-Level Generators that feed power into the ISO controlled grid without passing through a distribution level substation.

For Distribution-Level generation (a), essentially all generation was assumed to serve load connected at the common substation. This assumption was validated by PG&E's Distribution Planning Department and can be verified with hard data. This generation was used as a proxy for local load served by the substation and "netted out" in calculating Effective Net load.

For Transmission-Level generation (b), generators were identified that could serve load without using facilities under ISO control. Associated local load was "netted out" of this generation to arrive at Effective Net load in these instances.

Results:

Distribution-Level generation: Avg. = 62,211 MWh /month = .940% Service Area Gross Load

Data period (Jan 2002 – June 2003)

Transmission-Level generation: Avg. = 2,276 MWh/month = 0.034% Service Area Gross Load

Data period (Feb 2002 – Nov 2002) ***

"Effective Net Load" reduction = 0.974% of Gross Load

*** Data Periods differ due to availability of information on Transmission Level generation/load combinations.

City of Riverside Response to August 1, 2003 Information Request

From: Delgado, Robert
Sent: Friday, August 08, 2003 11:28 AM
To: Arikawa, Ben
Cc: Delgado, Robert
Subject: Re: Conference call info, documents, responses and information request

Ben,

The City of Riverside has four 10mw simple-cycle combustion turbines and generators which are solely under local control located within the city limits at our Springs Substation. On average they supplied .167% of our load for each of the first six months of 2003.

Robert Delgado
City of Riverside
909-351-6312

Turlock Irrigation District Response

To

California ISO August 1, 2003

Information Request

CEC-1304 Schedule 1 Part A **Power Plant Identification**

Reporting Period Year: 2002
Quarter: Fourth

Line No.		
1	**Plant Name**	Don Pedro
2	**CEC Plant ID**	H0144
3	**EIA Plant ID**	439
4	**Plant Location**	
4a	Street Address	21 Bonds Flat Rd
4b	City	La Grange
4c	County	Tuolumne
4d	State	CA
4e	Zip Code	95329
4f	Latitude (optional)	37d41'51.21402"N
4g	Longitude (optional)	120d25'12.85134"W
5	**Plant Owner**	
5a	Full Legal Name	Turlock Irrigation District
5b	Street Address	333 E. Canal Dr.
5c	City	Turlock
5d	State	CA
5e	Zip Code	95380
6	**Plant Operator**	(Leave blanks if it is the same as owner)
6a	Full Legal Name	
6b	Street Address	
6c	City	
6d	State	
6e	Zip Code	
7	**Nameplate Capacity (MW)**	181.90
8	**Number of Generators**	4
9	**Customer Classification Code of Cogeneration Thermal Host**	
10	**Customer Classification Code of Onsite Electricity User**	
11	**Date of Sale (during Reporting Period)**	
12	**Purchaser of Plant (during Reporting Period)**	
12a	Full Legal Name	
12b	Street Address	
12c	City	
12d	State	
12e	Zip Code	
12f	Contact Person	
12g	Telephone Number	
	Notes	68.46% owned by TID, 31.54% owned by Modesto Irrigation District. Actual

CEC-1304 Schedule 1 Part A **Power Plant Identification**

Reporting Period Year: 2002
Quarter: Fourth

Line No.		
1	**Plant Name**	Almond
2	**CEC Plant ID**	G0016
3	**EIA Plant ID**	7315
4	**Plant Location**	
4a	Street Address	4500 Crows Landing Road
4b	City	Modesto
4c	County	Stanislaus
4d	State	CA
4e	Zip Code	95358
4f	Latitude (optional)	37d34'27.94053"N
4g	Longitude (optional)	120d59'06.06369"W
5	**Plant Owner**	
5a	Full Legal Name	Turlock Irrigation District
5b	Street Address	333 E. Canal Dr.
5c	City	Turlock
5d	State	CA
5e	Zip Code	95380
6	**Plant Operator**	(Leave blanks if it is the same as owner)
6a	Full Legal Name	
6b	Street Address	
6c	City	
6d	State	
6e	Zip Code	
7	**Nameplate Capacity (MW)**	49.00
8	**Number of Generators**	1
9	**Customer Classification Code of Cogeneration Thermal Host**	
10	**Customer Classification Code of Onsite Electricity User**	
11	**Date of Sale (during Reporting Period)**	
12	**Purchaser of Plant (during Reporting Period)**	
12a	Full Legal Name	
12b	Street Address	
12c	City	
12d	State	
12e	Zip Code	
12f	Contact Person	
12g	Telephone Number	
	Notes	

CEC-1304 Schedule 1 Part A **Power Plant Identification**

Reporting Period Year: 2002
Quarter: Fourth

Line No.		
1	**Plant Name**	Walnut
2	**CEC Plant ID**	G0662
3	**EIA Plant ID**	4256
4	**Plant Location**	
4a	Street Address	325 s. Washington Road
4b	City	Turlock
4c	County	Stanislaus
4d	State	CA
4e	Zip Code	95380
4f	Latitude (optional)	37d29'25.02284"N
4g	Longitude (optional)	120d54'15.81953"W
5	**Plant Owner**	
5a	Full Legal Name	Turlock Irrigation District
5b	Street Address	333 E. Canal Dr.
5c	City	Turlock
5d	State	CA
5e	Zip Code	95380
6	**Plant Operator**	(Leave blanks if it is the same as owner)
6a	Full Legal Name	
6b	Street Address	
6c	City	
6d	State	
6e	Zip Code	
7	**Nameplate Capacity (MW)**	49.00
8	**Number of Generators**	2
9	**Customer Classification Code of Cogeneration Thermal Host**	
10	**Customer Classification Code of Onsite Electricity User**	
11	**Date of Sale (during Reporting Period)**	
12	**Purchaser of Plant (during Reporting Period)**	
12a	Full Legal Name	
12b	Street Address	
12c	City	
12d	State	
12e	Zip Code	
12f	Contact Person	
12g	Telephone Number	
	Notes	

CEC-1304 Schedule 1 Part A **Power Plant Identification**

Reporting Period Year: 2002
Quarter: Fourth

Line No.		
1	**Plant Name**	La Grange
2	**CEC Plant ID**	H0276
3	**EIA Plant ID**	440
4	**Plant Location**	
4a	Street Address	1249 La Grange Dam Road
4b	City	La Grange
4c	County	Tuolumne
4d	State	CA
4e	Zip Code	95329
4f	Latitude (optional)	37d40'10.80794"N
4g	Longitude (optional)	120d26'36.79948"W
5	**Plant Owner**	
5a	Full Legal Name	Turlock Irrigation District
5b	Street Address	333 E. Canal Dr.
5c	City	Turlock
5d	State	CA
5e	Zip Code	95380
6	**Plant Operator**	(Leave blanks if it is the same as owner)
6a	Full Legal Name	
6b	Street Address	
6c	City	
6d	State	
6e	Zip Code	
7	**Nameplate Capacity (MW)**	4.58
8	**Number of Generators**	2
9	**Customer Classification Code of Cogeneration Thermal Host**	
10	**Customer Classification Code of Onsite Electricity User**	
11	**Date of Sale (during Reporting Period)**	
12	**Purchaser of Plant (during Reporting Period)**	
12a	Full Legal Name	
12b	Street Address	
12c	City	
12d	State	
12e	Zip Code	
12f	Contact Person	
12g	Telephone Number	
	Notes	

CEC-1304 Schedule 1 Part A **Power Plant Identification**

Reporting Period Year: 2002
Quarter: Fourth

Line No.		
1	**Plant Name**	Hickman
2	**CEC Plant ID**	H0234
3	**EIA Plant ID**	162
4	**Plant Location**	
4a	Street Address	779 Main Canal
4b	City	Hickman
4c	County	Stanislaus
4d	State	CA
4e	Zip Code	95323
4f	Latitude (optional)	37d37'18.52420"N
4g	Longitude (optional)	120d44'46.10113"W
5	**Plant Owner**	
5a	Full Legal Name	Turlock Irrigation District
5b	Street Address	333 E. Canal Dr.
5c	City	Turlock
5d	State	CA
5e	Zip Code	95380
6	**Plant Operator**	(Leave blanks if it is the same as owner)
6a	Full Legal Name	
6b	Street Address	
6c	City	
6d	State	
6e	Zip Code	
7	**Nameplate Capacity (MW)**	1.10
8	**Number of Generators**	2
9	**Customer Classification Code of Cogeneration Thermal Host**	
10	**Customer Classification Code of Onsite Electricity User**	
11	**Date of Sale (during Reporting Period)**	
12	**Purchaser of Plant (during Reporting Period)**	
12a	Full Legal Name	
12b	Street Address	
12c	City	
12d	State	
12e	Zip Code	
12f	Contact Person	
12g	Telephone Number	
	Notes	

CEC-1304 Schedule 1 Part A **Power Plant Identification**

Reporting Period Year: 2002
Quarter: Fourth

Line No.		
1	**Plant Name**	Upper Dawson
2	**CEC Plant ID**	H0535
3	**EIA Plant ID**	489
4	**Plant Location**	
4a	Street Address	707 La Grange Dam Road
4b	City	La Grange
4c	County	Tuolumne
4d	State	CA
4e	Zip Code	95329
4f	Latitude (optional)	37d39'02.86438"N
4g	Longitude (optional)	120d28'14.84430"W
5	**Plant Owner**	
5a	Full Legal Name	Turlock Irrigation District
5b	Street Address	333 E. Canal Dr.
5c	City	Turlock
5d	State	CA
5e	Zip Code	95380
6	**Plant Operator**	(Leave blanks if it is the same as owner)
6a	Full Legal Name	
6b	Street Address	
6c	City	
6d	State	
6e	Zip Code	
7	**Nameplate Capacity (MW)**	4.80
8	**Number of Generators**	1
9	**Customer Classification Code of Cogeneration Thermal Host**	
10	**Customer Classification Code of Onsite Electricity User**	
11	**Date of Sale (during Reporting Period)**	
12	**Purchaser of Plant (during Reporting Period)**	
12a	Full Legal Name	
12b	Street Address	
12c	City	
12d	State	
12e	Zip Code	
12f	Contact Person	
12g	Telephone Number	
	Notes	

CEC-1304 Schedule 1 Part A **Power Plant Identification**

Reporting Period Year: 2002
Quarter: Fourth

Line No.		
1	**Plant Name**	Turlock Lake
2	**CEC Plant ID**	H0530
3	**EIA Plant ID**	161
4	**Plant Location**	
4a	Street Address	21642 Davis Road
4b	City	Hickman
4c	County	Stanislaus
4d	State	CA
4e	Zip Code	95323
4f	Latitude (optional)	37d36'41.36846"N
4g	Longitude (optional)	120d35'43.48307"W
5	**Plant Owner**	
5a	Full Legal Name	Turlock Irrigation District
5b	Street Address	333 E. Canal Dr.
5c	City	Turlock
5d	State	CA
5e	Zip Code	95380
6	**Plant Operator**	(Leave blanks if it is the same as owner)
6a	Full Legal Name	
6b	Street Address	
6c	City	
6d	State	
6e	Zip Code	
7	**Nameplate Capacity (MW)**	3.27
8	**Number of Generators**	3
9	**Customer Classification Code of Cogeneration Thermal Host**	
10	**Customer Classification Code of Onsite Electricity User**	
11	**Date of Sale (during Reporting Period)**	
12	**Purchaser of Plant (during Reporting Period)**	
12a	Full Legal Name	
12b	Street Address	
12c	City	
12d	State	
12e	Zip Code	
12f	Contact Person	
12g	Telephone Number	
	Notes	

CEC-1304 Schedule 1 Part B

Generator Information

Reporting Period Year: 2002
Quarter: Fourth

Don Pedro

CEC Plant ID: H0144
EIA Plant ID: 439

Line No.		
1	**Generator (Unit) ID**	6710282
2	**Generator Nameplate Capacity (MW)**	47.90
3	**Date of Initial Operation**	May 1971
4	**Operating Status**	Operating
5	**Date of Retirement (if retired during reporting period)**	
6	**Prime Mover Type**	HY
7	**Number of Wind Turbines**	
8	**Part of Combined-cycle Unit?** (Yes/No)	No
	Notes	Actual generation is greater than

CEC-1304 Schedule 1 Part B

Generator Information

Reporting Period	
Year:	2002
Quarter:	Fourth

Don Pedro

CEC Plant ID:	H0144
EIA Plant ID:	439

Line No.		
1	**Generator (Unit) ID**	6710283
2	**Generator Nameplate Capacity (MW)**	47.90
3	**Date of Initial Operation**	May 1971
4	**Operating Status**	Operating
5	**Date of Retirement (if retired during reporting period)**	
6	**Prime Mover Type**	HY
7	**Number of Wind Turbines**	
8	**Part of Combined-cycle Unit?** (Yes/No)	No
	Notes	Actual generation is greater than

CEC-1304 Schedule 1 Part B

Generator Information

Reporting Period	Year:	2002
	Quarter:	Fourth

Don Pedro

CEC Plant ID:	H0144
EIA Plant ID:	439

Line No.		
1	Generator (Unit) ID	8513242
2	Generator Nameplate Capacity (MW)	38.20
3	Date of Initial Operation	April 1989
4	Operating Status	Operating
5	Date of Retirement (if retired during reporting period)	
6	Prime Mover Type	HY
7	Number of Wind Turbines	
8	Part of Combined-cycle Unit? (Yes/No)	No
	Notes	

CEC-1304 Schedule 1 Part B

Generator Information

Reporting Period	Year:	2002
	Quarter:	Fourth

Almond

CEC Plant ID:	G0016
EIA Plant ID:	7315

Line No.		
1	**Generator (Unit) ID**	Unit 1
2	**Generator Nameplate Capacity (MW)**	49.00
3	**Date of Initial Operation**	October 1995
4	**Operating Status**	Operating
5	**Date of Retirement (if retired during reporting period)**	
6	**Prime Mover Type**	GT
7	**Number of Wind Turbines**	
8	**Part of Combined-cycle Unit?** (Yes/No)	Yes
	Notes	

CEC-1304 Schedule 1 Part B

Generator Information

Reporting Period Year: 2002
Quarter: Fourth

Walnut

CEC Plant ID: G0662
EIA Plant ID: 4256

Line No.		
1	Generator (Unit) ID	212813
2	Generator Nameplate Capacity (MW)	24.58
3	Date of Initial Operation	April 1986
4	Operating Status	Operating
5	Date of Retirement (if retired during reporting period)	
6	Prime Mover Type	GT
7	Number of Wind Turbines	
8	Part of Combined-cycle Unit? (Yes/No)	No
	Notes	

CEC-1304 Schedule 1 Part B

Generator Information

Reporting Period	Year:	2002
	Quarter:	Fourth

Walnut

CEC Plant ID:	G0662
EIA Plant ID:	4256

Line No.		
1	**Generator (Unit) ID**	212814
2	**Generator Nameplate Capacity (MW)**	24.58
3	**Date of Initial Operation**	April 1986
4	**Operating Status**	Operating
5	**Date of Retirement (if retired during reporting period)**	
6	**Prime Mover Type**	GT
7	**Number of Wind Turbines**	
8	**Part of Combined-cycle Unit?** (Yes/No)	No
	Notes	

CEC-1304 Schedule 1 Part B

Generator Information

Reporting Period

Year:	2002
Quarter:	Fourth

La Grange

CEC Plant ID:	H0276
EIA Plant ID:	440

Line No.		
1	**Generator (Unit) ID**	342321
2	**Generator Nameplate Capacity (MW)**	1.20
3	**Date of Initial Operation**	November 1989
4	**Operating Status**	Operating
5	**Date of Retirement (if retired during reporting period)**	
6	**Prime Mover Type**	HY
7	**Number of Wind Turbines**	
8	**Part of Combined-cycle Unit?** (Yes/No)	No
	Notes	

CEC-1304 Schedule 1 Part B

Generator Information

Reporting Period Year: 2002
Quarter: Fourth

La Grange

CEC Plant ID: H0276
EIA Plant ID: 440

Line No.		
1	**Generator (Unit) ID**	117954
2	**Generator Nameplate Capacity (MW)**	3.38
3	**Date of Initial Operation**	November 1989
4	**Operating Status**	Operating
5	**Date of Retirement (if retired during reporting period)**	
6	**Prime Mover Type**	HY
7	**Number of Wind Turbines**	
8	**Part of Combined-cycle Unit?** (Yes/No)	No
	Notes	

CEC-1304 Schedule 1 Part B

Generator Information

Reporting Period Year: 2002
Quarter: Fourth

Hickman

CEC Plant ID: H0234
EIA Plant ID: 162

Line No.		
1	Generator (Unit) ID	8383762
2	Generator Nameplate Capacity (MW)	0.54
3	Date of Initial Operation	September 1979
4	Operating Status	Operating
5	Date of Retirement (if retired during reporting period)	
6	Prime Mover Type	HY
7	Number of Wind Turbines	
8	Part of Combined-cycle Unit? (Yes/No)	No
	Notes	

CEC-1304 Schedule 1 Part B

Generator Information

Reporting Period Year: 2002
Quarter: Fourth

Hickman

CEC Plant ID: H0234
EIA Plant ID: 162

Line No.		
1	Generator (Unit) ID	8383763
2	Generator Nameplate Capacity (MW)	0.54
3	Date of Initial Operation	September 1979
4	Operating Status	Operating
5	Date of Retirement (if retired during reporting period)	
6	Prime Mover Type	HY
7	Number of Wind Turbines	
8	Part of Combined-cycle Unit? (Yes/No)	No
	Notes	

CEC-1304 Schedule 1 Part B

Generator Information

Reporting Period Year: 2002
Quarter: Fourth

Upper Dawson

CEC Plant ID: H0535
EIA Plant ID: 489

Line No.		
1	**Generator (Unit) ID**	KB69067L1
2	**Generator Nameplate Capacity (MW)**	4.80
3	**Date of Initial Operation**	November 1983
4	**Operating Status**	Operating
5	**Date of Retirement (if retired during reporting period)**	
6	**Prime Mover Type**	HY
7	**Number of Wind Turbines**	
8	**Part of Combined-cycle Unit?** (Yes/No)	No
	Notes	

CEC-1304 Schedule 1 Part B

Generator Information

Reporting Period Year: 2002
Quarter: Fourth

Turlock Lake

CEC Plant ID: H0530
EIA Plant ID: 161

Line No.		
1	Generator (Unit) ID	8383764
2	Generator Nameplate Capacity (MW)	1.09
3	Date of Initial Operation	July 1980
4	Operating Status	Operating
5	Date of Retirement (if retired during reporting period)	
6	Prime Mover Type	HY
7	Number of Wind Turbines	
8	Part of Combined-cycle Unit? (Yes/No)	No
	Notes	

CEC-1304 Schedule 1 Part B

Generator Information

Reporting Period Year: 2002
Quarter: Fourth

Turlock Lake

CEC Plant ID: H0530
EIA Plant ID: 161

Line No.		
1	Generator (Unit) ID	8383765
2	Generator Nameplate Capacity (MW)	1.09
3	Date of Initial Operation	July 1980
4	Operating Status	Operating
5	Date of Retirement (if retired during reporting period)	
6	Prime Mover Type	HY
7	Number of Wind Turbines	
8	Part of Combined-cycle Unit? (Yes/No)	No
	Notes	

CEC-1304 Schedule 1 Part B

Generator Information

Reporting Period Year:	2002
Quarter:	Fourth

Turlock Lake

CEC Plant ID:	H0530
EIA Plant ID:	161

Line No.		
1	Generator (Unit) ID	8383766
2	Generator Nameplate Capacity (MW)	1.09
3	Date of Initial Operation	July 1980
4	Operating Status	Operating
5	Date of Retirement (if retired during reporting period)	
6	Prime Mover Type	HY
7	Number of Wind Turbines	
8	Part of Combined-cycle Unit? (Yes/No)	No
	Notes	

CEC-1304 Schedule 2 Part A

Generation and Fuel Use by Generator

Reporting Period Year: 2002
Quarter: Fourth

Almond

CEC Plant ID: G0016
EIA Plant ID: 7315
Generator (Unit) ID:

				Primary Energy Source Type:		NG	Secondary Energy Source Type:		
Month	Gross MWh	Net MWh	Available MW @ System Peak	Fuel Use in MCF, bbl. or ton	Fuel Use in MMBtu	Fuel Cost*	Fuel Use in MCF, bbl. or ton	Fuel Use in MMBtu	Fuel Cost*
January	30,728	29,769	49.0	284,140 mcf	288,402				
February	26,632	25,796	49.0	247,136 mcf	251,337				
March	28,170	27,326	0.0	256,819 mcf	260,671				
April	3,160	2,975	49.0	29,982 mcf	30,312				
May	280	171	0.0	2,370 mcf	2,403				
June	720	592	0.0	6,987 mcf	7,071				
July	17,670	17,016	49.0	155,928 mcf	158,267				
August	2,820	2,639	49.0	25,115 mcf	25,492				
September	9,130	8,762	49.0	82,160 mcf	83,228				
October	3,200	3,002	0.0	29,084 mcf	29,520				
November	6,680	6,391	49.0	60,775 mcf	61,565				
December	260	131	0.0	2,521 mcf	2,561				
Annual Total**	129,450	124,570		1,183,017 mcf	1,200,829				
Notes									

* Fuel Cost is required for plants of 50 MW or more; it may be reported with a 3-month lag. Fuel Cost will be kept as confidential.

** For plants with plant nameplate capacity of less than 10 MW, monthly data are not required.

(1 MMBtu = 10 therms)

CEC-1304 Schedule 2 Part A

Generation and Fuel Use by Generator

Reporting Period	Year:	2002
	Quarter:	Fourth

Walnut

CEC Plant ID:	G0662
EIA Plant ID:	4256
Generator (Unit) ID:	

				Primary Energy Source Type:		NG	Secondary Energy Source Type:		DFO
Month	**Gross MWh**	**Net MWh**	**Available MW @ System Peak**	**Fuel Use in MCF, bbl. or ton**	**Fuel Use in MMBtu**	**Fuel Cost***	**Fuel Use in MCF, bbl. or ton**	**Fuel Use in MMBtu**	**Fuel Cost***
January	0	-42	49.0	0 mcf	0				
February	661	615	49.0	10,820 mcf	11,004				
March	101	65	49.0	1,720 mcf	1,744				
April	62	28	49.0	1,070 mcf	1,083				
May	34	2	49.0	640 mcf	649				
June	34	11	49.0	584 mcf	596				
July	580	534	49.0	10,162 mcf	10,355				
August	45	15	49.0	730 mcf	744				
September	174	142	49.0	2,996 mcf	3,041				
October	53	21	49.0	1,037 mcf	1,056				
November	36	1	49.0	768 mcf	780				
December	28	-17	49.0	555 mcf	564				
Annual Total**	1,808	1,375		31,082 mcf	31,616				
Notes	We do not have individual generator (unit) amounts.								

* Fuel Cost is required for plants of 50 MW or more; it may be reported with a 3-month lag. Fuel Cost will be kept as confidential.

** For plants with plant nameplate capacity of less than 10 MW, monthly data are not required.

(1 MMBtu = 10 therms)

CEC-1304 Schedule 2 Part A

Generation and Fuel Use by Generator

Reporting Period	Year:	2002
	Quarter:	Fourth

La Grange

CEC Plant ID:	H0276
EIA Plant ID:	440
Generator (Unit) ID:	

				Primary Energy Source Type:		WAT	Secondary Energy Source Type:		DFO
Month	**Gross MWh**	**Net MWh**	**Available MW @ System Peak**	**Fuel Use in MCF, bbl. or ton**	**Fuel Use in MMBtu**	**Fuel Cost***	**Fuel Use in MCF, bbl. or ton**	**Fuel Use in MMBtu**	**Fuel Cost***
January									
February									
March									
April									
May									
June									
July									
August									
September									
October									
November									
December									
Annual Total**	10,115	10,051							
Notes									

* Fuel Cost is required for plants of 50 MW or more; it may be reported with a 3-month lag. Fuel Cost will be kept as confidential.

** For plants with plant nameplate capacity of less than 10 MW, monthly data are not required. **(1 MMBtu = 10 therms)**

CEC-1304 Schedule 2 Part A

Generation and Fuel Use by Generator

Reporting Period Year: 2002
Quarter: Fourth

Hickman

CEC Plant ID: H0234
EIA Plant ID: 162
Generator (Unit) ID:

				Primary Energy Source Type:		WAT	Secondary Energy Source Type:		DFO
Month	**Gross MWh**	**Net MWh**	**Available MW @ System Peak**	**Fuel Use in MCF, bbl. or ton**	**Fuel Use in MMBtu**	**Fuel Cost***	**Fuel Use in MCF, bbl. or ton**	**Fuel Use in MMBtu**	**Fuel Cost***
January									
February									
March									
April									
May									
June									
July									
August									
September									
October									
November									
December									
Annual Total**	4,302	4,265							
Notes									

* Fuel Cost is required for plants of 50 MW or more; it may be reported with a 3-month lag. Fuel Cost will be kept as confidential.

** For plants with plant nameplate capacity of less than 10 MW, monthly data are not required. **(1 MMBtu = 10 therms)**

CEC-1304 Schedule 2 Part A

Generation and Fuel Use by Generator

Reporting Period Year: 2002
Quarter: Fourth

Upper Dawson

CEC Plant ID: H0535
EIA Plant ID: 489
Generator (Unit) ID:

				Primary Energy Source Type: WAT			Secondary Energy Source Type: DFO		
Month	**Gross MWh**	**Net MWh**	**Available MW @ System Peak**	**Fuel Use in MCF, bbl. or ton**	**Fuel Use in MMBtu**	**Fuel Cost***	**Fuel Use in MCF, bbl. or ton**	**Fuel Use in MMBtu**	**Fuel Cost***
January									
February									
March									
April									
May									
June									
July									
August									
September									
October									
November									
December									
Annual Total**	11,033	10,886							
Notes									

* Fuel Cost is required for plants of 50 MW or more; it may be reported with a 3-month lag. Fuel Cost will be kept as confidential.

** For plants with plant nameplate capacity of less than 10 MW, monthly data are not required. **(1 MMBtu = 10 therms)**

CEC-1304 Schedule 2 Part A

Generation and Fuel Use by Generator

Reporting Period Year: 2002
Quarter: Fourth

Turlock Lake

CEC Plant ID: H0530
EIA Plant ID: 161
Generator (Unit) ID:

				Primary Energy Source Type:		WAT	Secondary Energy Source Type:		DFO
Month	**Gross MWh**	**Net MWh**	**Available MW @ System Peak**	**Fuel Use in MCF, bbl. or ton**	**Fuel Use in MMBtu**	**Fuel Cost***	**Fuel Use in MCF, bbl. or ton**	**Fuel Use in MMBtu**	**Fuel Cost***
January									
February									
March									
April									
May									
June									
July									
August									
September									
October									
November									
December									
Annual Total**	9,148	9,097							
Notes									

* Fuel Cost is required for plants of 50 MW or more; it may be reported with a 3-month lag. Fuel Cost will be kept as confidential.

** For plants with plant nameplate capacity of less than 10 MW, monthly data are not required.

(1 MMBtu = 10 therms)

CEC-1304 Schedule 2 Part B

Sales by Power Plant

Almond

Reporting Period	Year:	2002
	Quarter:	Fourth
	CEC Plant ID:	G0016
	EIA Plant ID:	7315

Month	Onsite Use MWh	Sales for Resale MWh	Sales to End-User 1 MWh	Customer Classification Code End-User 1	Sales to End-User 1 MWh	Customer Classification Code End-User 1
January			29,769.0			
February			25,796.0			
March			27,326.0			
April			2,975.0			
May			171.0			
June			592.0			
July			17,016.0			
August			2,639.0			
September			8,762.0			
October			3,002.0			
November			6,391.0			
December			131.0			
Annual Total**		*	124,570.0			
Notes	* We assume all sales for resale are made from purchases.					

* For plants with plant nameplate capacity of less than 10 MW, monthly data are not required.

CEC-1304 Schedule 2 Part B

Sales by Power Plant

Walnut

Reporting Period Year: 2002
Quarter: Fourth

CEC Plant ID: G0662
EIA Plant ID: 4256

Month	Onsite Use MWh	Sales for Resale MWh	Sales to End-User 1 MWh	Customer Classification Code End-User 1	Sales to End-User 1 MWh	Customer Classification Code End-User 1
January			0			
February			615			
March			65			
April			28			
May			2			
June			11			
July			534			
August			15			
September			142			
October			21			
November			1			
December			0			
Annual Total**		*	1,434			
Notes	* We assume all sales for resale are made from purchases.					

* For plants with plant nameplate capacity of less than 10 MW, monthly data are not required.

CEC-1304 Schedule 2 Part B

Sales by Power Plant

La Grange

Reporting Period Year: 2002
Quarter: Fourth

CEC Plant ID: H0276
EIA Plant ID: 440

Month	Onsite Use MWh	Sales for Resale MWh	Sales to End-User 1 MWh	Customer Classification Code End-User 1	Sales to End-User 1 MWh	Customer Classification Code End-User 1
January						
February						
March						
April						
May						
June						
July						
August						
September						
October						
November						
December						
Annual Total**		*	10,051			
Notes	* We assume all sales for resale are made from purchases.					

* For plants with plant nameplate capacity of less than 10 MW, monthly data are not required.

CEC-1304 Schedule 2 Part B

Sales by Power Plant

Walnut

Reporting Period	Year:	2002
	Quarter:	Fourth
	CEC Plant ID:	H0234
	EIA Plant ID:	162

Month	Onsite Use MWh	Sales for Resale MWh	Sales to End-User 1 MWh	Customer Classification Code End-User 1	Sales to End-User 1 MWh	Customer Classification Code End-User 1
January						
February						
March						
April						
May						
June						
July						
August						
September						
October						
November						
December						
Annual Total**		*	4,265			
Notes	* We assume all sales for resale are made from purchases.					

* For plants with plant nameplate capacity of less than 10 MW, monthly data are not required.

CEC-1304 Schedule 2 Part B

Sales by Power Plant

Walnut

Reporting Period	Year:	2002
	Quarter:	Fourth
	CEC Plant ID:	H0535
	EIA Plant ID:	489

Month	Onsite Use MWh	Sales for Resale MWh	Sales to End-User 1 MWh	Customer Classification Code End-User 1	Sales to End-User 1 MWh	Customer Classification Code End-User 1
January						
February						
March						
April						
May						
June						
July						
August						
September						
October						
November						
December						
Annual Total**		*	10,886			
Notes	* We assume all sales for resale are made from purchases.					

* For plants with plant nameplate capacity of less than 10 MW, monthly data are not required.

CEC-1304 Schedule 2 Part B

Sales by Power Plant

Turlock Lake

Reporting Period

Year:	2002
Quarter:	Fourth
CEC Plant ID:	H0530
EIA Plant ID:	161

Month	Onsite Use MWh	Sales for Resale MWh	Sales to End-User 1 MWh	Customer Classification Code End-User 1	Sales to End-User 1 MWh	Customer Classification Code End-User 1
January						
February						
March						
April						
May						
June						
July						
August						
September						
October						
November						
December						
Annual Total**		*	9,097			
Notes	* We assume all sales for resale are made from purchases.					

* For plants with plant nameplate capacity of less than 10 MW, monthly data are not required.

CEC-1304 Schedule 2 Part B

Sales by Power Plant

Don Pedro

Reporting Period

Year:	2002
Quarter:	Fourth
CEC Plant ID:	H0144
EIA Plant ID:	439

Month	Onsite Use MWh	Sales for Resale MWh	Sales to End-User 1 MWh	Customer Classification Code End-User 1	Sales to End-User 1 MWh	Customer Classification Code End-User 1
January			4,812.0			
February			4,058.0			
March			37,898.0			
April			61,684.0			
May			54,277.0			
June			54,212.0			
July			66,306.0			
August			52,675.0			
September			28,672.0			
October			18,617.0			
November			5,899.0			
December			6,800.0			
Annual Total**		*	395,910.0			
Notes	* We assume all sales for resale are made from purchases.					

* For plants with plant nameplate capacity of less than 10 MW, monthly data are not required.

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* REGISTERED TO PRACTICE BEFORE THE U.S. PATENT AND TRADEMARK OFFICE

** NOT ADMITTED IN DC

August 28, 2003

To: Kim Hubner
Executive Assistant, California Independent System Operator Corporation

Fr: Sean M. Neal
Attorney for the Modesto Irrigation District

Re: Documents Concerning ISO Staff's August 22, 2003 *Response to Board Inquiries on Potential Changes to Billing Determinants*

Ms. Hubner:

Please find enclosed: a) an August 28, 2003 memorandum from Dr. Laurence D. Kirsch to the ISO Board of Governors entitled "Comment on the ISO Staff's *Response to Board Inquiries on Potential Changes to Billing Determinants*," and b) an August 28, 2003 letter from myself to the ISO Board of Governors entitled "Comments on ISO Staff's August 22, 2003 *Response to Board Inquiries on Potential Changes to Billing Determinants*."

MID would be grateful if the ISO would post these documents on the ISO website in its GMC Stakeholder Process section. Also, please circulate the attached documents to the persons listed below. The Board of Governors has been mailed these documents directly. Thank you.

Respectfully yours,

/s/ Sean Neal
Sean M. Neal
Attorney for the
Modesto Irrigation District

Cc:\\ Bill Regan
Phil Leiber
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* REGISTERED TO PRACTICE BEFORE THE U.S. PATENT AND TRADEMARK OFFICE

** NOT ADMITTED IN DC

August 28, 2003

To: Board of Governors
California Independent System Operator Corporation

Fr: Sean M. Neal
Attorney for the Modesto Irrigation District

Re: Comments on ISO Staff's August 22, 2003 *Response to Board Inquiries on Potential Changes to Billing Determinants*

Writing on behalf of the Modesto Irrigation District ("MID"), I wish to raise to the Board's attention certain omissions and errors in the California Independent System Operator Corporation's ("ISO") Staff's August 22, 2003, *Response to Board Inquiries on Potential Changes to Billing Determinants* ("August 22 Staff Report").

First, the August 22 Staff Report does not describe why MID advocates allocation of the Grid Management Charge ("GMC") in a manner whose mathematical result is comparable to net treatment, and thereby leaves the incorrect impression that the fundamental difference between the ISO Staff Proposal and the MID Proposal is the concept of "net v. gross". The factual errors in the ISO Staff's characterization of the MID GMC proposal are addressed by Dr. Laurence D. Kirsch in an accompanying memorandum.

The "net v. gross" argument was not raised by either MID or ISO Staff during the GMC 2004 stakeholder process. Rather, the current discussion of "net v.

gross" arises from Federal Energy Regulatory Commission's ("Commission") Order on the 2001-2003 GMC, otherwise known as Opinion No. 463,[1] and the various requests for clarification and rehearing of that Opinion. In its request for clarification, MID pointed out that if the allocation of GMC is based on net load as a billing determinant, net treatment is appropriate only for entities that have the ability to balance load and generation behind-the-meter.[2]

MID's position is based on MID's Interconnection Agreement ("IA") with PG&E,[3] under which all of MID's resources and loads are aggregated at MID's interconnection with PG&E-owned transmission at MID's Westley substation. Contractually, all of MID's loads and resources are deemed to be behind-the-meter for the purpose of determining MID's net interchange with PG&E. Because PG&E is not currently the Control Area Operator for Northern California, MID's net interchange with PG&E is equivalent to MID's net interchange with the CAISO.

From time to time, MID does purchase power from various suppliers and such power is delivered to MID via the CAISO-Controlled Grid. Although these resources are also be deemed to be behind-the-meter under the PG&E IA, MID does not claim that such resources should be deemed behind-the-meter for the purpose of determining what portion of MID load is served from behind-the-meter generation. Rather, these deliveries constitute MID's use of the CAISO-Controlled Grid.

The IA also relieves PG&E of any "obligation to serve" MID's customers and requires MID to plan and operate its system to acquire resources in an amount sufficient to both satisfy both its customer demand and Western Electricity Coordinating Council ("WECC") reserve requirements.

The ISO Staff states that "we remain unchanged in our view that municipal utility behind-the-meter load should be fully metered and assessed on this gross metered basis." See August 22 Staff Report at 14. However, the ISO Staff recommends exempting Qualifying Facility ("QF") standby load. *See id.* at 13. Such a recommendation ignores the fact that MID provides insurance higher in quality to such QFs, as MID self-provides WECC reserves in the same amount as any control area operator. Further, as a municipal utility with a diversified portfolio of resources, MID has an inherently greater ability than a stand-alone QF to ensure continuity of service to its load.

Moreover, the August 22 Staff Report omits a complete analysis of Opinion No. 463 wherein the Commission gave clear direction to the ISO that as a

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1 "Opinion and Order on Initial Decision," *California Independent System Operator Corp.*, 103 FERC ¶ 61,114, Docket Nos. ER01-313, *et al.* (May 2, 2003) ("Opinion No. 463").

2 See June 2, 2003 "Request for Clarification and Rehearing of the Modesto Irrigation District" at 4-7, 10-11in Docket Nos. ER01-313, et al; June 16, 2003 "Answer of the Modesto Irrigation District to Multiple Parties' Motions for Clarification" at 5-8 in Docket Nos. ER01-313, et al.; June 23, 2003, "Reply of the Modesto Irrigation District to Answer to Motions for Clarification of the California Independent System Operator Corporation" at 2-5.

3 MID's IA is on file with the Commission as Rate Schedule FERC No. 116.

principle, it desired GMC to be allocated to entities with behind-the-meter generation, based on their use of the CAISO-Controlled Grid.

In particular, Paragraph 28 of Opinion No. 463 stated that: "Customers with behind-the-meter generation who primarily rely on that generation to meet their energy needs have made a convincing argument that use of gross load results in this customer class being allocated too great a share of CAS [Control Area Services] costs." The August 22 Staff Response also contradicts the plain language of Opinion No. 463, Paragraph 34, which states "...behind-the-meter customers, wholesale or retail, with a generator that has a capacity factor of 50 percent or more, are to be allocated CAS costs based on their highest monthly demand. This exception applies to whether the behind-the-meter generation is wholesale or retail." Opinion No. 463 clearly makes no distinction between retail and wholesale behind-the-meter load.

However, the August 22 ISO Staff Report does not focus its analysis on the Commission's ruling in Opinion No. 463, but rather on the Initial Decision[4] which was the subject of Opinion No. 463. The ISO Staff's emphasis on the Initial Decision leaves the impression that the Initial Decision approving the use of Gross Control Area Load is the controlling law of the case. *See* August 22 Staff Report at 7. It is not. The Commission's ruling on the Initial Decision, in Opinion No. 463, constitutes the controlling law, and Opinion No. 463 requires that customers that primarily rely on behind-the-meter generation be allocated GMC based on a basis less than Control Area Gross Load. Further Opinion No. 463 does not differentiate between customers with behind-the-meter generation, such as QFs and Governmental Entities.

MID requests that the Board take into account these matters in reaching its final decision as to the August 22 Staff Report and the GMC Stakeholder process.

Respectfully yours,

/s/ Sean Neal

Sean M. Neal
Attorney for the
Modesto Irrigation District

Cc:\\ Bill Regan
Phil Leiber
Ben Arikawa
Deborah Le Vine
Stephen Morrison

4 "Initial Decision," *California Independent System Operator Corp.*, 99 FERC ¶ 63,020, Docket Nos. ER01-313, *et al.* (2002) ("Initial Decision").

CHRISTENSEN ASSOCIATES

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Voice 608.231.2266 Fax 608.231.2108

TO: Board of Governors, California Independent System Operator

FROM: Dr. Laurence D. Kirsch, Christensen Associates

DATE: August 28, 2003

SUBJECT: Comment on the ISO Staff's *Response to Board Inquiries on Potential Changes to Billing Determinants*

In its *Response to Board Inquiries on Potential Changes to Billing Determinants* dated August 22, the ISO Staff characterizes the Modesto Irrigation District's GMC proposal as a "net-based" approach (p. 7) founded in "net concepts" (p. 11) and including "net components" (p. 12). I wish to take issue with that characterization.

While it is true that the MID proposal would have the ISO recover 54% of its costs according to a billing determinant that is mathematically equivalent to what the ISO Staff calls "net load," the proposal is not based on a "net load" concept. Instead, it is based on the principle that the ISO's customers should pay for the services that they use, and should not pay taxes based upon something other than their use. As I have explained to the ISO's Finance Committee, the services that customers use are things that customers can measurably affect, not the activities that the ISO performs. Thus, while the ISO performs many activities that together assure system reliability, customers do not use a vaguely defined and unmeasurable "reliability service." What ISO customers *do* use are the ISO's power balancing services and flow management services, both of which are measurable and are subject to at least some customer control; and it is the competence with which the ISO performs these measurable services that together constitute virtually all of what is meant by "reliability."

The ISO Staff proposal, by contrast, asserts that 39% and 20% of the ISO's costs are incurred to provide "Core Reliability Services" and "Settlements, Metering and Customer Relations" service, respectively.[1] Our objection to these services is not that they are based upon gross load, but that they are fictional: "Core Reliability Services" is just a made-up name, not a measurable service that customers use; and although "Settlements, Metering and Client Relations" is

[1] P. Leiber and D. LeVine, *Rate Structure Proposal For the 2004 GMC Rate Structure Project*, June 25, 2003, p. 13.

arguably a real service with costs that depend upon customer actions and characteristics, its $47.9 million of cost is so implausibly large relative to the services performed that the Staff has proposed to recover these costs through a blatant tax on four other services.[2]

The difference between the MID proposal and the ISO Staff proposal is not one of "net" vs. "gross." The difference is that the MID proposal is designed to recover all ISO costs through charges on the customers' measurable uses of ISO services, while the ISO Staff proposal recovers a majority of the ISO's costs through taxes rather than through charges on customers' uses of ISO services.

[2] *Ibid.*, p. 18.

To: ISO Board Finance Committee

SCE has reviewed the recommendations contained in the August 22 "Report on GMC Issues Raised by Board on July 24, 2003", and would like to make the following comments. With respect to the issue of the assessment of the Core Reliability Services (CRS) Charge to "behind-the-meter" (BTM) load, SCE's main concern throughout the stakeholder process has been that the GMC should be assessed on a comparable and non-discriminatory basis to all Scheduling Coordinators. That concern was the basis for SCE's proposed definition of "Grid Demand", which considered the amount of generation on the distribution systems of Scheduling Coordinators representing utilities in order that IOUs and muni utilities be assessed the GMC on a comparable basis. Although the ISO management has recommended the rejection of SCE's proposed Grid Demand definition, SCE considers that the alternative conclusion reached by the ISO management is an acceptable resolution of the BTM net versus gross issues. The ISO management proposal would assess the CRS component of the GMC to all Scheduling Coordinators representing utilities with wholesale BTM load and BTM generation on a gross load basis, but not assess retail BTM load taking standby service on a gross basis.

As SCE indicated in its comments at the July 17 Finance Committee meeting, SCE was supportive of the ISO management's proposal with two exceptions. The first was that there be comparable determination of billing determinants for the CRS and ETS components of the GMC. In SCE's view, this concern is satisfied if the Board adopts the recommendation of the ISO management on the BTM issues. The second was that there should be appropriate consideration of the unique aspects of energy that serves load in other control areas delivered over non-ISO controlled grid facilities, that is not the load responsibility of the ISO (the Mohave issue). The current ISO proposal does not contain any such recognition. Therefore, SCE cannot unequivocally support the ISO management proposal, but does support it with this exception.

Bert Hansen

Southern California Edison

Comments of CAC/EPUC:

On behalf of the Cogeneration Association of California (CAC) and the Energy Producers and Users Coalition (EPUC), we would like to express our appreciation to the Committee for their willingness to listen to the comments presented by stakeholders and for allowing further consideration of issues based upon those comments.

We would also like to thank the ISO's 2004 GMC team for their efforts in working with stakeholders and being willing to consider alternatives to the ISO's use of a gross load billing determinant for the behind-the-meter standby class.

In prior presentations to the Committee we referenced recent decisions from FERC in the 2001 GMC and TAC proceedings in which FERC rejected gross load as a billing determinant for the behind-the-meter standby class. We also mentioned that a final decision in the QF PGA proceeding was still pending before FERC. As Mr. Arikawa and Mr. Leiber mentioned during the conference call, that decision, Opinion No. 464, was issued on August 12, 2003 and is accurately summarized in Staff's Report of August 22, 2003.

CAC and EPUC support Staff's recommendation as contained in the Report as regards net billing for the behind-the-meter standby class. It is also our opinion that resolution of this issue as proposed by Staff will serve to avoid unnecessary litigation, is consistent with Opinion No. 464, and we look forward to supporting the resolution before FERC.

Thank you for the opportunity to present these comments.

Rod Aoki and Jim Ross
for CAC/EPUC

Finance Committee
Board of Governors

9/5/03

2004 GMC Rate Structure

MOVED, that the Finance Committee of the ISO Board recommends approval of the revised staff proposal for GMC rate recovery methodology for 2004, reflecting the modifications proposed in the August 22, 2003 report on potential changes to billing determinants.

Moved: Florio **Second: Gage**

Finance Committee Action: **Passed** Vote Count: **2-0-0**	
Florio	Y
Gage	Y

CALIFORNIA ISO

2004 GMC Rate Structure Project
List of documents provided under the Non-Disclosure Agreement

Item	Date	Revised Date	Parties receiving Item
2003 Cost Allocation Matrix (used in 2003 Budget, MS Excel spreadsheet)	1/16/03		MID, EOB, CAC, PG&E
2003 Cost Allocation Matrix, modified for Modesto Irrigation District (MS Excel spreadsheet)	1/16/03	2/12/03	MID, Navigant, NCPA, EOB
Board Budget Book (containing budget information sent to ISO Board, hardcopy only)	1/16/03		MID, EOB, CAC, PG&E, SCE
Uninstructed deviation data by SC (MS Access database)	1/27/03		MID (1/30/2003), Navigant Consulting (1/30/2003), EOB (1/29/2003), CAC (1/29/2003), PG&E (1/29/2003)
Capital Spending unbundling information from 2003 Budget (MS Excel spreadsheet: 2003 Capi without 2003 detail.xls)	1/28/03		MID, Navigant, NCPA, EOB, SCE
Capital Spending unbundling information from 2003 Budget (MS Excel spreadsheet: 2003 Unbundling details.xls)	2/4/03		MID, SCE
Budget allocation detail for cost centers 1424 and 1441 (MS Excel spreadsheet)	2/12/03		MID, Navigant, NCPA, EOB, SCE
2003 Cost Allocation Matrix, modified for Modesto Irrigation District (MS Excel spreadsheet) containing MID cost assignments (received from MID on 03/03/2003)	3/5/03		Navigant, EOB, CAC, CDWR, PG&E, SCE
2003 Cost Allocation Matrix, modified for SCE (MS Excel spreadsheet)	4/7/03		Posted on confidential discussion board
Functional Assignment of CAISO Systems.doc - This is a Word document that contains a listing of ISO systems with their assignment to the functions.	4/18/03		Posted on confidential discussion board
2003 Direct Labor Ratios .xls - This Excel spreadsheet contains the direct staff assignments to the ISO proposed functions.	4/18/03		Posted on confidential discussion board
2004 Cost Allocation Matrix using 2003 Budget Modified JC.xls - This Excel spreadsheet contains the Cost Allocation Matrix. This file is linked with the "2003 Direct Labor Ratios .xls" spreadsheet.	4/18/03		Posted on confidential discussion board
SCECostAllocation4-07-03.xls: 2003 cost allocation matrix containing SCE assignment of costs	4/21/03		Posted on confidential discussion board
GMCDirect Assignments4-08-03.xls: SCE direct assignments	4/21/03		Posted on confidential discussion board
GMC Analysis Tool- 2004-SCE-masked.xls: bill impacts under SCE rate proposal	4/25/03		Posted on confidential discussion board
GMC Analysis Tool- 2004-MID-masked.xls: bill impacts under MID rate proposal	4/25/03		Posted on confidential discussion board
GMC Analysis Tool 2004-ISO-masked.xls: bill impacts under ISO rate proposal	4/25/03		Posted on confidential discussion board
Net Uninstructed Energy database with SC IDs masked per the bill impact spreadsheets	5/2/03		MID(Hemphill 5/2/2003), EOB (Lam 5/6/2003)
Impact of Mohave rate by SC - ISO proposal 030509 NDA version.xls - spreadsheet showing the bill impacts of a rate for Mohave generation equal to 10 percent of the CRS and ETS rates	5/9/03		SCE (Bert Hansen)
SCE DDES impact by SC 030509 NDA version.xls - spreadsheet showing the bill impacts of a rate for Mohave generation equal to 10 percent of the SCE's CAS rate	5/9/03		SCE (Bert Hansen)
Impact of 12 CP vs. 12 NCP rate by SC - ISO proposal 030508 -NDA version.xls - spreadsheet showing the bill impacts of using 12 CP vs 12 NCP under the ISO proposal	5/9/03	5/13/03	Posted on confidential discussion board, revised document includes charts, posted on May 13, 2003
Bill Impacts - ISO proposal 030512.ppt - presentation for May 12th meeting containing histograms and scatter plots of bill impacts	5/12/03		Distributed during meeting and e-mailed 5/12/2003
SCE 25 percent DDES impact by SC 030515 NDA ver.xls - spreadsheet showing bill impacts of DDES rate set to 25 percent of applicable CAS	5/15/03		Posted on confidential discussion board, sent separately to David Cohen
SCE 10 percent DDES impact by SC 030515 NDA ver.xls - spreadsheet showing bill impacts of DDES rate set to 10 percent of applicable CAS	5/15/03		Posted on confidential discussion board, sent separately to David Cohen
Impact of 10 prnt Mohave rate - ISO proposal 030514 NDA ver.xls - spreadsheet showing bill impacts of DDES rate set to 10 percent of applicable CRS and ETS	5/15/03		Posted on confidential discussion board, sent separately to David Cohen
Impact of 25 prnt Mohave rate - ISO proposal 030514 NDA ver.xls - spreadsheet showing bill impacts of DDES rate set to 25 percent of applicable CRS and ETS	5/15/03		Posted on confidential discussion board, sent separately to David Cohen
Bill Impacts 6-06-03 NDA version.xls - spreadsheet containing bill impacts for all proposals updated to reflect data cleanup. Distributed after June 4th meeting	6/6/03		Posted on confidential discussion board, sent separately to David Cohen
Bill impacts Bill Impacts 7-08-03 nda.xlsBill Impacts 7-08-03 nda.xls - spreadsheet containing bill impacts for all proposals updated to reflect data cleanup and including final versions of each proposal	7/8/03		Posted on confidential discussion board
Uninstructed deviation data by SC September 2001 through February 2003 (MS Access database)	7/22/03		Mirant, CAC/EPUC, MID, CDWR, Navigant, EOB
Midway-Sunset data used in bill impact analysis, data covers September 2001 through April 2003	8/5/03		Rod Aoki, Jim Ross
Riverside bill impact analysis using data for January-February 2003	9/3/03		Robert Delgado

Created by: Ben Arikawa
Last Updated: September 5, 2003

Finance Committee 9/5/03
Board of Governors 9/25/03

2004 GMC Rate Structure

MOVED, that the ISO Board approves the revised staff proposal for GMC rate recovery methodology for 2004, reflecting the modifications proposed in the August 22, 2003 report on potential changes to billing determinants.

Moved: Florio **Second: Gage**

Finance Committee Action: **Passed** Vote Count: **2-0-0**	
Florio	Y
Gage	Y

Moved: Gage **Second: Florio**

Board Action: **Passed** Vote Count: **4-0-0**	
Florio	Y
Gage	Y
Guardino	X
Kahn	Y
Miramontes	Y

Attachment 50
List of members of GMC WG e-mail distribution list

1 Alessandri, Patrick – EOB
2 Alvidres, Jane – Edison Mission
3 Aoki, Rod – CAC/EPUC
4 Arikawa, Ben – ISO
5 Arredondo, Jesus – NRG Energy
6 Auclair, Philippe – Mirant
7 Barkovich, Barbara – Barkovich & Yap
8 Bechard, Tom – Powerex
9 Blevin, Ray – CAC/EPUC
10 Bonaly, David – CDWR
11 Bosowski, David – MID
12 Bougher, Nancy – (City of) Roseville
13 Electric
14 Bracht, Kirk – CPUC
15 Bray, Peter – PG&E
16 Brommer, Mike – TID
17 Brown, Andy – IEP
18 Brown, Layne – Duke Energy
19 Cash-Hunter, Betty – Sempra
20 Cogdill, Jan – ISO
21 Cohen, David – Navigant Consulting
22 Comnes, Alan – Dynegy
23 Delgado, Robert – City of Riverside
24 Downey, Carrie – IID
25 Edmister, Todd – CPUC
26 Epstein, Mike – ISO
27 Farrar, Mike – TID
28 Faust, Charles – FERC
29 Finch, Shelley – Edison Mission
30 Firooz, Sharon – SDG&E
31 Franklin, Brett – EOB
32 Frazee, Matt – City of Anaheim
33 Guss, Charles – City of Anaheim
34 Hale, Rowena – PG&E
35 Hansen, Bert – SCE
36 Hemphill, Ross – Laurence Christensen
37 Associates
38 Hitson, Brian – PG&E
39 Hoffman, Kyle – ISO
40 Ivancovich, Anthony – ISO
41 Jackson, Blair – MID
42 Jaffe, Ken – Swidler Berlin
43 Kaplan, Katie – IEP
44 Kargoll, Bob – PG&E
45 Kasarjian, Vicken – NCPA
46 Kehrein, Carolyn – EMS
47 Kirsch, Laurence - Laurence Christensen
48 Associates
49 Kissel, Peter –
50 Kolakowski, Victoria – EOB
51 Kreamer, Mike – MID
52 Kurniawan, Villyady – Mapvision
53 Lam, Tony – EOB
54 Le Vine, Debi – ISO
55 Leiber, Phil – ISO
56 Lengenfelder, David – FERC
57 Leung, Herman – City of Riverside
58 Lindh, Karen – Lindh & Associates
59 Lucero, Ed – SDG&E
60 Lyon, Deane – ISO
61 Markey, Gerald – ISO
62 McGuffin, Mike – ISO
63 Menzel, Eric – PG&E
64 Mi, Jingchao – CDWR
65 Montini, Raymond – FERC
66 Moore, Julia – Swidler Berlin
67 Morrison, Stephen – ISO
68 Neal, Sean
69 Nolff, Gary – City of Riverside
70 Olsson, Ray – EOB
71 Paradise, Theodore – Swidler Berlin
72 Peterson, Mike – ISO
73 Pompel, Leslie – BPA
74 Pritchard, Jan – MID
75 Regan, William – ISO
76 Rochlin, Cliff – Sempra
77 Ross, James A – CAC/EPUC
78 Ryan, Mike – WAPA
79 Sandino, David – CDWR
80 Schueurman, Paul –
81 Schneider, Susan – Phoenix Consulting
82 Schoenbeck, Don – CAC/EPUC
83 Shea, Karen – CPUC
84 Smith, Kevin – CMUA
85 Solomon, Tom – TID
86 Springer, John – ISO
87 Stevener, Donna – City of Riverside
88 Stillwagon, Gerry – MID
89 Takehara, James – NCPA
90 Terry, Lee – CDWR
91 Timson, David – ISO
92 Uhler, LeeAnne – City of Riverside

Attachment 50
List of members of GMC WG e-mail distribution list

93 Van Hoy, Roger – MID
94 Wakade, Gourang –
95 Walz, Edna – California Attorney General
96 Weisel, Ken – TID
97 Withrow, David – ISO
98 Wright, Kathleen – CERS
99 Yakin, Dale – PG&E
100 Yap, Catherine – Barkovich & Yap
101 Yoho, Allen – ISO

Usernames and Passwords for GMC Discussion Boards

Last Name	First	Afiliation
Aoki	Rod	CAC/EPUC
Auclair	Philippe	Mirant
Barkovich	Barbara	B&Y
Black	Shannon	SMUD
Bonaly	David	CDWR
Bosowski	Dale	MID
Bray	Peter	PG&E
Brommer	Michael	TID
Cameron	Arlene	ISO
Cash-Hunter	Betty	SDG&E
Cohen	David	Navigant
Delgado	Robert	Riverside
Firooz	Sharon	SDG&E
Frazee	Mark	Anaheim
Guss	Charles	Anaheim
Hansen	Bert	SCE
Kaplan	Katie	IEP
Kirsch	Laurence	MID
Kissel	Peter	CDWR
Lam	Tony	EOB
LeVine	Debi	ISO
Mi	Jingchao	CDWR
Neal	Sean	
Pompel	Leslie	BPA
Ross	James	CAC/EPUC
Ryan	Mike	WAPA
Slaton	Jeff	EOB
Smith	Kevin	CMUA
Springer	John	ISO
Stillwagon	Gerry	MID
Takehara	James	NCPA
Terry	Lee	CDWR
Withrow	David	ISO
Yakin	Dale	PG&E

Attachment 2 - Stakeholder Process Contacts

	Date	Person(s)	Recipient	Type	Description
1	4-Dec-02	Mike McGuffin, ISO	Jan Pritchard, MID	E-Mail Communication	E-mail message contains Ben Arikawa's request to Mike McGuffin to contact Jan Pritchard to discussion types of deviation data available from ISO.
2	5-Dec-02	Jan Pritchard, MID	Mike McGuffin, ISO	E-Mail Communication	E-mail response of MID to above e-mail.
3	17-Dec-02	Ben Arikawa, ISO	Jan Pritchard, Laurence Kirsch and Ross Hemphill	E-Mail Communication and attached Word document	E-mail transmitting ISO's understanding of deviation data needed by MID. Documentation describing how net deviation from schedule data meets MID's definition of deviations.
4	17-Dec-02	Laurence Kirsch, MID	Ben Arikawa	Memorandum	Dr. Kirsch provided revisions of billing determinant data descriptions and confirmed that net deviations described in above document met MID's definition of deviations. Also questioned if net control area load plus exports met MID's definition of net power withdrawals from ISO-controlled grid.
5	17-Dec-02	Ben Arikawa, ISO	Jan Pritchard, Laurence Kirsch and Ross Hemphill	E-Mail Communication and attached Word document	Communication detailing changes made in definitions of billing determinants data to reflect discussions with MID. Confirmation that net power withdrawals from ISO-controlled grid are equivalent to net control area load.
6	19-Dec-02	Ross C. Hemphill	Ben Arikawa, ISO	E-Mail Communication and attached Word document	Dr. Hemphill criticized participants and ISO for inconsistent and inaccurate use of terminology. Dr. Hemphill suggested that the ISO use their rate consultants, Barkovich and Yap, to propose an "industry standard" structure for cost accounting for the ISO.
7	6-Jan-03	Ross C. Hemphill	Ben Arikawa, ISO	E-Mail Communication and attached Word document	Dr. Hemphill commented on the usefulness of the ISO's grouping of activities for MID's development of its rate proposal. Dr. Hemphill argued that the ISO should allocate its costs to the four functions proposed by MID.
8	13-Jan-03	Ben Arikawa	Jan Pritchard, Ross Hemphill, and Laurence Kirsch, MID	E-Mail Communication	ISO proposed to hold a conference call with MID to discuss MID's concerns on functionalization.
9	13-Jan-03			Meeting at ISO	Regular meeting of 2004 GMC Rate Structure Project. Identified need to have follow-up discussions with MID
10	13-Jan-03	Ben Arikawa	GMC WG e-mail distribution list	E-Mail Communication	ISO listed scheduling of MID/ISO conference call as an outstanding item from January 13th meeting
11	14-Jan-03	Ben Arikawa	Jan Pritchard	E-Mail Communication	ISO confirmed tentative time for conference call with MID for January 16th 9:30 to 11:00.
12	15-Jan-03	Jan Pritchard	Ben Arikawa	E-Mail Communication	MID asked for confirmation of time and date of conference call
13	15-Jan-03	Ben Arikawa	GMC WG e-mail distribution list	E-Mail Communication	ISO confirmed time for conference call with MID for January 16th 9:30 to 11:00.
14	16-Jan-03			Conference call	Conference call with MID, open to all participants in 2004 GMC Rate Structure project
15	16-Jan-03	Ben Arikawa	GMC WG e-mail distribution list	E-Mail Communication	Summary of discussion during conference call. Notes reviewed by MID prior to general distribution. ISO and MID agreed to distribution of interval level deviation subject to market notice. Also, the ISO would provide additional data and documentation to MID. (See below.) MID would prepare documentation (Statement BA) to better describe MID proposed functions. Next conference call scheduled for January 23rd, 9-11 am.
16	16-Jan-03	Phil Leiber	Jan Pritchard, Sean Neal, Ross Hemphill, and Laurence Kirsch, MID	E-Mail Communication with attachments	Transmittal of modified cost allocation matrix to MID, links to operational audit and SAS 70 report. Confirmation that ISO Board Budget Book was being sent via Federal Express. Documents and data sent as agreed to on conference call.
17	16-Jan-03	ISO Client Relations	ISO Market Participants	E-Mail Communication	ISO Market Notice detailing proposed release of SC specific deviation data. Allows seven days for SCs to protest release.
18	21-Jan-03	Ross Hemphill	Ben Arikawa	E-Mail Communication with attachments	MID transmits Statement BA to ISO with descriptions of rate functions.
19	22-Jan-03	Ben Arikawa	Jan Pritchard, Laurence Kirsch and Ross Hemphill	E-Mail Communication	ISO transmittal of agenda to MID. Agenda had been modified during a telephone discussion between Ben Arikawa and Ross Hemphill.
20	22-Jan-03	Ben Arikawa	GMC WG e-mail distribution list	E-Mail Communication with attachments	ISO transmittal of conference call information, agenda and MID's Statement BA to participants
21	23-Jan-03			Conference call	Conference call with MID, open to all participants in 2004 GMC Rate Structure project
22	23-Jan-03	Phil Leiber	David Hawkins and Deane Lyon	Internal ISO e-mail communication	Notice to Grid Operations directors that MID requires their assistance in developing cost assignments.
23	23-Jan-03	Phil Leiber	Jan Pritchard, Sean Neal, Ross Hemphill, and Laurence Kirsch, MID	E-mail communication	Confirmation that ISO will make available two directors from Grid Operations to answer questions. ISO provided these directors' schedules.
24	24-Jan-03	Ben Arikawa	GMC WG e-mail distribution list	E-Mail Communication	Notice of conference call with call in information
25	24-Jan-03	Ben Arikawa	Jan Pritchard, Laurence Kirsch and Ross Hemphill	E-Mail Communication with attachments	ISO transmittal of draft meeting notes to MID for review
26	27-Jan-03	Laurence Kirsch	Ben Arikawa, Jan Pritchard, Sean Neal and Ross Hemphill	E-Mail Communication with attachments	MID markup of meeting notes
27	28-Jan-03	Ben Arikawa	Jan Pritchard, Laurence Kirsch and Ross Hemphill	E-Mail Communication with attachments	Transmittal of additional detail of bond-financed capital expenditures and a description of activities included in ASREO function.
28	28-Jan-03	Ben Arikawa	GMC WG e-mail distribution list	E-Mail Communication with attachments	Transmittal of January 23rd meeting notes to participants in 2004 GMC Rate Structure Project
29	28-Jan-03	Laurence Kirsch	Ben Arikawa	E-Mail Communication with attachments	Transmittal of spreadsheet detailing preliminary functional assignments and document discussing how assignments were made and where additional information was needed.
30	29-Jan-03	Ben Arikawa	Laurence Kirsch, Ross Hemphill, Jan Pritchard	E-Mail Communication	Request for agenda items for January 30th conference call
31	29-Jan-03	Laurence Kirsch	Ben Arikawa	E-Mail Communication	Response of Dr. Kirsch to request for agenda items.
32	29-Jan-03	Ross Hemphill	Ben Arikawa, Jan Pritchard, Laurence Kirsch	E-Mail Communication	Transmittal of proposed agenda for next ISO/MID conference call scheduled for January 30th.
33	29-Jan-03	Ben Arikawa	GMC WG distribution list	E-Mail Communication with attachments	Transmittal to participants of non-confidential documents sent to MID, notification of confidential documents sent, notice of call in number and agenda for MID/ISO January 30th conference call.
34	30-Jan-03			Conference call	Conference call between MID and ISO, open to all participants.
35	30-Jan-03	Ross Hemphill	Ben Arikawa	E-Mail Communication	As discussed during the conference call, MID transmitted schedules of Drs. Kirsch and Hemphill
36	31-Jan-03	Ben Arikawa	Laurence Kirsch, Ross Hemphill, Jan Pritchard	E-Mail Communication with attachments	Transmittal of draft meeting notes to MID for review. Confirmation that ISO is prepared to discuss Grid Operations activities on February 3rd.
37	31-Jan-03	Ross Hemphill	Ben Arikawa	E-Mail Communication	Reviewed meeting notes with minor changes.
38	31-Jan-03	Ben Arikawa	GMC WG distribution list	E-Mail Communication with attachments	Transmittal of non-confidential data and MID/ISO conference call notes.
39					
40	31-Jan-03	Ben Arikawa	Keith Casey, Jan Cogdill, Bruce Drummond, Kyle Hoffman, Eric Leuze, Ali Miremadi, David Hawkins, Deane Lyon,	Internal e-mail Communication with attachments	Transmittal of relevant documents to prepare ISO staff for conference calls with MID.
41	31-Jan-03	Ben Arikawa	Michelle Gamble	Internal e-mail Communication	Request to schedule conferences with relevant staff and MID
42	31-Jan-03	Ben Arikawa	Keith Casey, Jan Cogdill, Bruce Drummond, Kyle Hoffman, Eric Leuze, Ali Miremadi, David Hawkins, Deane Lyon,	Internal e-mail Communication	Invitation to staff to listen in on first MID/ISO conference call on Grid Operations activities
	3-Feb-03			Conference call	Conference call between ISO and MID concerning Grid Operations activities
43	3-Feb-03	Ben Arikawa	GMC WG e-mail distribution list	E-Mail Communication	Brief report of results of conference call with MID. Call in information for February 4th conference call on capital expenditures and bond financing.
44	3-Feb-03	Laurence Kirsch	Ben Arikawa, David Hawkins	E-Mail Communication with attachments	Transmittal of changes as a result of conversation between ISO and MID on Grid Operations.
45	3-Feb-03	Ben Arikawa	Laurence Kirsch	E-mail communication	Review of consistency of results. Pointing to potential error.

Attachment 2 - Stakeholder Process Contacts

	Date	Person(s)	Recipient	Type	Description
46	3-Feb-03	Phil Leiber	Ross Hemphill, Laurence Kirsch, Jan Pritchard	E-Mail Communication	Transmittal of market notice of 2002 PwC Operational Audit results
47	3-Feb-03	Laurence Kirsch	Ben Arikawa	E-Mail Communication with attachments	Dr. Kirsch confirms that there is mistake in cost assignment for RMR software. Updated cost assignment spreadsheet is sent.
48	4-Feb-03			Conference call	Conference call with MID and ISO on bond financed and capital expenditures
49	4-Feb-03	Phil Leiber	GMC WG e-mail distribution list	E-Mail Communication	Summary of conference call on bond financing and capital expenditures and call information for next conference call.
50	4-Feb-03	Phil Leiber	Laurence Kirsch, Ross Hemphill, Jan Pritchard, Sean Neal	E-Mail Communication and attachment	Additional information concerning capital expenditures on software systems and their assignment to functions.
51	5-Feb-03			Conference call	Conference call with MID and ISO staff on activities in Market Analysis and Compliance
52	5-Feb-03	Ben Arikawa	GMC WG e-mail distribution list, Keith Casey, Eric Leuze	E-mail Communication	Summary of conference call with MID and ISO staff on Market Analysis and Compliance activities
53	5-Feb-03	Laurence Kirsch	Ben Arikawa	E-Mail Communication with attachments	Transmittal of updated spreadsheet to ISO by MID
54	5-Feb-03	Ben Arikawa	Greta Ossman, Bruce Drummond, Ali Miremadi, Kyle Hoffman, Eric Leuze, Jan Cogdill	Internal e-mail Communication	Transmittal of revised MID spreadsheet to ISO staff for review.
55 56 57	6-Feb-03	Ben Arikawa	Jan Pritchard, Laurence Kirsch, Ross Hemphill	E-Mail Communication	ISO requests feedback on MID views on progress of conference calls.
58	6-Feb-03	Greta Ossman	Allen Jaschke, Leslie Feusi, Mel Abueg, Eric Whitley, Bruce Drummond, Ben Arikawa	Internal e-mail communication with attachments	Internal communication in preparation for conference call with MID on February 7th.
59	7-Feb-03			Conference call	Conference call with MID and ISO staff concerning activities in Information Services cost centers.
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61	10-Feb-03			Conference call	Conference call with MID and ISO staff concerning Market Services activities
62	10-Feb-03	Laurence Kirsch	Ben Arikawa	E-Mail Communication	Communication regarding activities in cost center 1723
63	12-Feb-03	Ben Arikawa	Laurence Kirsch	E-Mail Communication	Transmittal of revised cost allocation matrix and documentation on cost centers 1424 and 1441 provided under the Non-Disclosure Agreement
64	14-Feb-03	Ben Arikawa	GMC WG e-mail distribution list	E-Mail Communication with attachments	Transmittal of various documents in preparation for February 19th GMC meeting. Includes a brief summary of conference calls held with MID regarding activities in ISO cost centers
	19-Feb-03			Meeting at PG&E in San Francisco	Participants with rate proposals given opportunity to make presentations. SCE, MID and ISO presented their rate design proposals.
65	21-Feb-03	Ben Arikawa	Laurence Kirsch, Jan Pritchard	E-Mail Communication	Follow-up to ensure that MID had sufficient information from ISO concerning cost center 1731.
66	21-Feb-03	Laurence Kirsch	Ben Arikawa	E-Mail Communication	Confirmation that MID had received sufficient information to complete its cost assignment of cost center 1731
67	28-Feb-03	Ben Arikawa	Jan Pritchard, Bert Hansen	E-Mail Communication	Confirmation that MID and SCE would be available for the scheduled March 4, 2003 conference call to discuss rate proposals
68	3-Mar-03	Laurence Kirsch	Ben Arikawa, Phil Leiber, Jan Pritchard, Ross Hemphill	E-Mail Communication with attachments	Transmittal of MID modified Cost Allocation Matrix and MID "GMC Rate Design" paper for discussion on March 4, 2003 conference call.
69	3-Mar-03	Ben Arikawa	GMC WG e-mail distribution list	E-Mail Communication with attachments	Transmittal of MID "GMC Rate Design" paper to participants, URLs of additional meeting documents and February 19, 2003 meeting notes.
70	4-Mar-03			Conference Call	Conference call to discuss progress on proposals, whether parties need additional assistance from ISO. MID discussed its proposal with other participants.
71	5-Mar-03	Ben Arikawa	EOB (Lisa Wolfe, Tony Lam, Brett Franklin, Patrick Alessandri, Ray Olsson), PG&E (Dale Yakin), Navigant (David Cohen), CAC/EPUC (Rod Aoki, Don Schoenbeck, Jim Ross), CDWR (Jingchao Mi, Peter Kissel)	E-Mail Communication with attachments	Distribution of MID modified Cost Allocation Matrix to parties that requested a copy and that were covered by Non-disclosure Certificate
72	10-Mar-03	Laurence Kirsch	Stephen Morrison, Sean Neal, Jan Pritchard	E-Mail Communication with attachments	Transmittal of revised "GMC Rate Design" paper
73	11-Mar-03	Ben Arikawa	Jan Pritchard, Laurence Kirsch, Ross Hemphill	E-Mail Communication	Informing MID that Ben Arikawa will make a Market Issues Forum presentation on the status of the 2004 GMC Rate Structure Project. Included will be a discussion of each of the rate proposals before the participants.
74	11-Mar-03	Jan Pritchard	Ben Arikawa, Sean Neal, Laurence Kirsch, Ross Hemphill, Mike Kreamer, Roger Van Hoy	E-Mail Communication	Request that ISO inform MIF attendees of availability of MID proposal and encourage attendees to participate on March 17, 2003 conference call.
75	12-Mar-03	Ben Arikawa	Sean Neal, Laurence Kirsch, Ross Hemphill, Mike Kreamer, Roger Van Hoy, Stephen Morrison, Phil Leiber	E-Mail Communication	Response to MID request confirming that ISO will give URL of 2004 GMC Rate Structure Project documents and will post the MID "GMC Rate Design" paper as soon as confidentiality of the document is reviewed
76	12-Mar-03	Ben Arikawa	Sean Neal, Laurence Kirsch, Ross Hemphill, Mike Kreamer, Roger Van Hoy, Stephen Morrison, Phil Leiber	E-Mail Communication	URL of ISO MIF presentation on status of GMC Rate Structure Project
77	12-Mar-03	Ben Arikawa	Sean Neal, Laurence Kirsch, Ross Hemphill, Mike Kreamer, Roger Van Hoy, Stephen Morrison, Phil Leiber	E-Mail Communication	Updated URL of ISO MIF presentation on status of GMC Rate Structure Project
78	13-Mar-03	Ben Arikawa		Market Issues Forum Presentation	Presentation describing status of 2004 GMC Rate Structure Project and the three rate proposals (including MID's) under consideration.
79	13-Mar-03	Ben Arikawa	GMC WG e-mail distribution list	E-Mail Communication with attachments	Transmittal of proposed March 17, 2003 conference call agenda and latest version of MID "GMC Rate Design" paper
80	17-Mar-03			Conference call	2004 GMC Rate Structure Project conference call. One topic was the discussion of MID proposal
81	24-Mar-03	Ben Arikawa	GMC WG e-mail	E-Mail Communication with attachments	Distribution of March 17, 2003 conference call notes
82	10-Apr-03	Laurence Kirsch	Ben Arikawa	E-Mail Communication with attachments	Laurence Kirsch's presentation for the April 11, 2003 GMC meeting
83	11-Apr-03			GMC meeting	MID made presentation on its rate proposal
84	15-Apr-03	Laurence Kirsch	Ben Arikawa, Debi Le Vine, Phil Leiber, Jan Pritchard, Sean Neal and Ross Hemphill	E-Mail Communication	Questions posed by Dr. Kirsch at the end of the April 11, 2003 GMC meeting
85	21-Apr-03	Ben Arikawa	Laurence Kirsch	E-Mail Communication with attachments	Transmittal of documents requested by Dr. Kirsch during phone conversation answering his April 15th questions
86	22-Apr-03	Ben Arikawa	Jan Pritchard, Bert Hansen	E-Mail Communication	Asked if MID and SCE would like to make presentation on example rate calculations as ISO would be doing at April 28th GMC meeting
87	23-Apr-03	Jan Pritchard	Ben Arikawa, Laurence Kirsch	E-Mail Communication	MID is interested, but like more information about the format of presentation
88	23-Apr-03	Ben Arikawa	Jan Pritchard, Laurence Kirsch	E-Mail Communication	ISO presentation not ready, but will keep MID informed
89	23-Apr-03	Ben Arikawa	Jan Pritchard, Laurence Kirsch, Mike McGuffin, Phil Leiber	E-Mail Communication	Transmitted updated billing determinants to MID prior to general release for their use in preparing for April 28th meeting
90	24-Apr-03	Laurence Kirsch	Ben Arikawa, Phil Leiber, Jan Pritchard, Ross Hemphill, Sean Neal	E-Mail Communication with attachments	Transmittal of updated MID rates using data from 04/23/2003.
91	24-Apr-03	Phil Leiber	Laurence Kirsch, Ben Arikawa, Jan Pritchard, Ross Hemphill, Sean Neal	E-Mail Communication	Bill impacts will be updated using new MID rates
92	24-Apr-03	Phil Leiber	Laurence Kirsch, Ben Arikawa, Jan Pritchard, Ross Hemphill, Sean Neal, Mike McGuffin	E-Mail Communication	Mr. Leiber noted some differences in billing determinants and the need to resolve these.

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	Date	Person(s)	Recipient	Type	Description
93	24-Apr-03	Laurence Kirsch	Phil Leiber, Ben Arikawa, Jan Pritchard, Ross Hemphill, Sean Neal, Mike McGuffin	E-Mail Communication	Dr. Kirsch explains differences and adopts ISO's number of customer months
94	24-Apr-03	Phil Leiber	Mike McGuffin, Ben Arikawa, Sean Neal, Jan Pritchard, Ross Hemphill	E-Mail Communication	Mr. Leiber asked Mike McGuffin to compile NCP based on MID's method
95	24-Apr-03	Laurence Kirsch	Phil Leiber, Ben Arikawa, Jan Pritchard, Ross Hemphill, Sean Neal, Mike McGuffin	E-Mail Communication	Dr. Kirsch looks forward to an ISO update on NCP
	24-Apr-03	Mike McGuffin	Phil Leiber, Ben Arikawa, Jan Pritchard, Ross Hemphill, Sean Neal,, Laurence Kirsch	E-Mail Communication	Mr. McGuffin explains that producing 12-month rolling averages is problematic.
96	24-Apr-03	Laurence Kirsch	Phil Leiber, Ben Arikawa, Jan Pritchard, Ross Hemphill, Sean Neal	E-Mail Communication with attachment	Dr. Kirsch transmits updated MID proposal and presentation for April 28th meeting
97	24-Apr-03	Laurence Kirsch	Ben Arikawa, Jan Pritchard, Ross Hemphill, Sean Neal, Mike McGuffin	E-Mail Communication	Dr. Kirsch explains how to create the 12 month average data for NCP
98	24-Apr-03	Phil Leiber	Mike McGuffin, Ben Arikawa, Sean Neal, Jan Pritchard, Ross Hemphill	E-Mail Communication	Mr. Leiber asks if it is necessary to wait until an acceptable NCP number is generated
	24-Apr-03	Phil Leiber	Mike McGuffin, Ben Arikawa, Sean Neal, Jan Pritchard, Ross Hemphill	E-Mail Communication	Mr. Leiber points out that there is an error in the number of schedules
99	25-Apr-03	Phil Leiber	Mike McGuffin, Ben Arikawa, Sean Neal, Jan Pritchard, Ross Hemphill	E-Mail Communication with attachment	Mr. Leiber transmits updated MID bill impacts using updated rates
100	25-Apr-03	Ben Arikawa	Ross Hemphill and Jan Pritchard	E-Mail Communication	Mr. Arikawa notifies MID attorney review is needed prior to release of data to MID
101	25-Apr-03	Ben Arikawa	Ross Hemphill and Jan Pritchard	E-Mail Communication with attachment	Mr. Arikawa transmits load and deviation data to MID
102	28-Apr-03	Ben Arikawa	Laurence Kirsch	E-Mail Communication with attachment	Mr. Arikawa transmits bill impact spreadsheets to Dr. Kirsch
103	29-Apr-03	Laurence Kirsch	Mike McGuffin, Ross Hemphill, Blagoy Borissov, Ben Arikawa	E-Mail Communication	Dr. Kirsch describes data to be burned to CD and Fed-Ex'ed to Blagoy Borissov
104	30-Apr-03	Ben Arikawa	Laurence Kirsch and Ross Hemphill	E-Mail Communication	Mr. Arikawa notifies Drs. Kirsch and Hemphill that data distribution will be delayed
105	2-May-03	Ben Arikawa	Laurence Kirsch, Ross Hemphill, Jan Pritchard, Phil Leiber, Stephen Morrison, Mike McGuffin and Debi Le Vine	E-Mail Communication	Mr. Arikawa notifies Drs. Kirsch and Hemphill that data will be sent out this day.
106	2-May-03	Mike McGuffin	Laurence Kirsch, Ross Hemphill, Jan Pritchard, Phil Leiber, Stephen Morrison, Ben Arikawa and Debi Le Vine	E-Mail Communication	Mr. McGuffin acknowledges that there are problems with the data that should be corrected.
107	6-May-03	Laurence Kirsch	Ben Arikawa, Mike McGuffin, Phil Leiber, Ross Hemphill, Jan Pritchard, Sean Neal	E-Mail Communication	Dr. Kirsch points to unexpectedly large bill impacts to a single masked SC ID.
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24-Jun-02	Jan Pritchard		phone call	Discussed potential meeting in Modesto to discuss 2003 GMC stakeholder process and GMC issues in general. Jan also gave me name and number of TID's Ass't General Manager, Ken Weisel.
25-Jun-02	Kevin Smith		phone call	Asked who relevant contacts at NCPA for GMC are
26-Jun-02	David Arthur		phone call	Discussed potential stakeholder process, if he might participate.
27-Jun-02	Andy Brown		phone call	Discussed potential stakeholder process. Andy will talk to Katie Kaplan about this.
27-Jun-02	Mike Werner		phone call	Discussed potential stakeholder process. Jing Chao Mi will participate for CDWR.
27-Jun-02	Phil Auclair		phone call	Discussed potential stakeholder process. Phil will discuss with Steve Huhman. Mirant is not in IEP.
01-Jul-02	Robert Pease		e-mail message	Mr. Pease noted that FERC Staff might be interested in observing the GMC rate redesign process. Identified Michael Coleman as possible contact.
01-Jul-02	David Cohen		phone call	Discussed TANC's concerns. Gave me Ed Lucero, Dan Metz and Jim Cuillier as contacts at SDG&E, PG&E and SCE, respectively.
01-Jul-02	Ed Chang		phone call	Discussed potential stakeholder process and WAPA's concerns. Debbie Dietz is GMC contact for WAPA.
01-Jul-02	Michelle Wynne		phone call	Discussed old stakeholder process. Would like to be kept informed of what is going on.
03-Jul-02	Jim Cuillier	Ben Arikawa	e-mail message	Mr. Cuillier identified Bert Hansen as SCE contact.
03-Jul-02	Katie Kaplan	Ben Arikawa	e-mail message	Ms. Kaplan expressed appreciation that ISO was contacting stakeholders prior to initiating process. Would be open to being on the committee if one is formed.
03-Jul-02	Lisa Wolfe		phone call	Discussed potential stakeholder process and use of rate design consultant.
03-Jul-02	Phil Auclair		phone call	Discussed where 2003 GMC was and Mirant's concerns about its participation.
05-Jul-02	Todd Edmister	Ben Arikawa	e-mail message	Mr. Edmister responded to earlier e-mail concerning possible rate design consultants.
08-Jul-02	Pamela Durgin	Ben Arikawa	e-mail message	Expressed interest in participating in GMC rate redesign process for CCSF.
08-Jul-02	Tony Braun	Ben Arikawa	e-mail message	Expressed interest in participating in GMC rate redesign process for CMUA
09-Jul-02	Dan Metz	Ben Arikawa	e-mail message	Expressed interest in participating in GMC rate redesign process for PG&E
09-Jul-02	Kevin Smith		phone call	Would like to see FERC involved at some level. Dave Dockham is NCPA contact.
09-Jul-02	Manuel Ramirez		phone call	Discussed stakeholder process and potential meeting days in San Francisco.
10-Jul-02	Ed Lucero	Ben Arikawa	e-mail message	Expressed interest in participating in GMC rate redesign process for SDG&E
11-Jul-02	Debbie Dietz		phone call	Discussed 2002 Settlement, 2003 budget process and potential stakeholder process. Set meeting for July 19 at WAPA
11-Jul-02	Lisa Wolfe		phone call	Discussed potential stakeholder process and issues.
11-Jul-02	Todd Edmister		phone call	Discussed meeting times at CPUC and possible joint meeting with CCSF. Set July 18 meeting

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12-Jul-02	Pamela Durgin		phone call	Discussed potential for meeting with CPUC jointly in SF.
16-Jul-02	Pamela Durgin		phone call	CCSF have no real issues with ISO GMC. Asks to be kept informed.
17-Jul-02	Ben Arikawa	Todd Edmister, Manuel Ramirez	e-mail message	Transmitted list of issues to discuss at meeting
17-Jul-02	Ben Arikawa	Michael Coleman, Robert Pease, Phil Leiber	e-mail message	To see if FERC staff has an interest in participating in the GMC project
17-Jul-02	Jan Pritchard		phone call	Discussed differences between 2002 Settlement, 2003 budget filing and rate redesign for 2004. Will try to see if next week is workable for a meeting in Modesto
17-Jul-02	Rod Aoki		phone call	Rod is taking over for Linda Sherif. Will see if a meeting time in SF is workable.
18-Jul-02	Todd Edmister, Kerry Hattevick, Manuel Ramirez, Ben Arikawa		meeting, CPUC	Meeting to discuss issues for stakeholder process.
19-Jul-02	Ben Arikawa	Edmister, Todd; Manuel Ramirez; Kerry Hattevik; Wolfe, Lisa; Tony Lam	e-mail message	Gave them URL of Ontario IMO study
19-Jul-02	ISO Market Notice	Market participants	Market Notice	Market Notice of Market Issues Forum Meeting and agenda with discussion of GMC rate redesign
19-Jul-02	Debbie Dietz, Steve Richardson, Sean Sanderson, Russell Knight, Mark White for WAPA. Mike Epstein, Kyle Hoffman and Ben Arikawa for ISO		Meeting, WAPA	Meeting to discuss issues for stakeholder process.
19-Jul-02	Jingchao Mi		phone call	Discussed potential stakeholder process and issues. Jingchao will see if CDWR wants to meet.
22-Jul-02	Ben Arikawa	Lisa Wolfe	e-mail message	Transmitted Alberta Power Pool Study
22-Jul-02	Ray Olson, Tony Lam and Lisa Wolfe and Ben Arikawa		meeting, EOB	Discussed outline of preliminary issues. Wanted to know to whom I've been speaking on GMC process.
22-Jul-02	Dan Metz		phone call	Discussed MIF presentation scheduled for July 25. Urged me to contact Ed Lucero. Discussed GMC settlement.
22-Jul-02	Ed Lucero		phone call	Discussed issues that SDG&E wanted reviewed in GMC process. What the ISO would use the rate consultant for.
23-Jul-02	Ben Arikawa	Edmister, Todd; Manuel Ramirez; Kerry Hattevik	e-mail message	Transmitted Alberta Power Pool Study
23-Jul-02	Ben Arikawa	Dan Metz, Ed Lucero	e-mail message	Sent list of preliminary issues to discuss
23-Jul-02	Bert Hansen		phone call	Discussed preliminary set of issues for stakeholder process. SCE will participate.
24-Jul-02	Ben Arikawa	Roger Van Hoy	e-mail message	Transmitted list of issues to discuss at meeting
24-Jul-02	Steve Huhman	Ben Arikawa	e-mail message	Responded to e-mail informing Mirant of MIF presentation.
24-Jul-02	Roger Van Hoy		phone call	Discussed MIF presentation scheduled for July 25. Discussed list of preliminary issues.
24-Jul-02	Shannon Black		phone call	Discussed MIF presentation scheduled for July 25. Discussed list of preliminary issues.
25-Jul-02	Jan Pritchard and Phil Leiber		Conversation	Discussed MID's position re GMC stakeholder process. MID may make Dr. Kirsch available to outline his proposal for GMC allocation.

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Date	Person(s)	Recipient	Type	Description
25-Jul-02	Ben Arikawa		MIF presentation	Presentation by Ben Arikawa on GMC Settlement, Initial Decision and need for stakeholder process. Byron Woertz made presentation on what form the process could take.
25-Jul-02	Dave Dockham		phone call	Discussed list of preliminary issues.
25-Jul-02	Tony Braun		phone call	Will come to MIF. Briefly discussed issues with stakeholder process
25-Jul-02	Ken Weisel		voicemail	Relevant contact at TID is Mike Brommer
26-Jul-02	Michele Wynne		Phone call	Discussed FERC technical conferences. GMC issues. Promised to send presentations from MIF and the preliminary list of issues.
02-Aug-02	ISO Market Notice	Market participants	Market Notice	Market Notice asking for comments on form of stakeholder review process for rate redesign for 2004.
02-Aug-02	Sean Neal	Terry Winter, Charles Robinson, Byron Woertz	Memorandum	Memorandum from MID to Terry Winter, Charles Robinson and Byron Woertz on MID's interest and concerns about a stakeholder advisory committee format for the rate redesign. MID is opposed to a stakeholder advisory committee.
02-Aug-02	Jan Pritchard		Phone call	MID will make Dr. Kirsch available on a limited basis. Their current idea of this is that Dr. Kirsch will write a short summary of his proposal and be available for a meeting with ISO staff. Dr. Kirsch will be available to comment or review ISO implementation of his proposal. No ideologues, strictly only the mechanics.
05-Aug-02	David Cohen		Phone call	Discussed GMC stakeholder process. Is writing something for TANC waiting for approval from members. Thinks that the people in the group will have sufficient experience so that we don't need a rate consultant.
05-Aug-02	Roger VanHoy		Phone call	Returned my call of Friday 8/2/2002. Discussed the stakeholder process briefly. I asked about a meeting. Set one for August 20 11:00 am. Later changed to Wed. Aug. 21 11:00 am to accommodate John Springer. I will send an agenda out before the meeting.
06-Aug-02	Ben Arikawa	Rod Aoki	e-mail message	Sent a list of issues (preliminary issues similar to that in GMC Settlement document)
07-Aug-02	David Cohen		Memorandum	Draft TANC comments on stakeholder advisory committee and scheduling
09-Aug-02	Debbie Dietz	Ben Arikawa	e-mail message	WAPA comments and concerns about GMC. Mike Ryan will be the WAPA contact on GMC.
09-Aug-02	Rod Aoki		Letter to Byron Woertz	Comments on CAC/EPUC views of rate redesign process opposing stakeholder advisory committee
13-Aug-02	Jan Pritchard		Phone call	Discussed ISO staff position on stakeholder process. Discussed meeting with MID next week.
16-Aug-02	Carolyn Kehrein	Ben Arikawa	e-mail message	Noted concerns with stakeholder advisory committee groupings.
16-Aug-02	Lisa Wolfe	Ben Arikawa	e-mail message	Noted concerns with stakeholder advisory committee, but EOB will participate regardless.
16-Aug-02	ISO Market Notice	Market participants	Market Notice	Market Notice informing market participants of the stakeholder process and asking for input on identifying members for stakeholder committee.
16-Aug-02	Jan Pritchard		Phone call	Discussed next week's meeting and agenda.

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19-Aug-02	Ben Arikawa	Rod Aoki	e-mail message	Sent Board contact info
19-Aug-02	Lisa Wolfe	Byron Woertz, Ben Arikawa	e-mail message	EOB raises concerns about the membership of stakeholder advisory committee and whether there would be one vote for all state agencies
19-Aug-02	Lisa Wolfe		Phone call	Clarify 2002-2003 GMC stakeholder meeting. Concerns over make up of committee. Whether or not EOB and CPUC reps will sit at the same time and share a vote. Ask her to submit questions directly to Byron concerning the EOB's issues.
19-Aug-02	Rod Aoki		Phone call	Discussed stakeholder procedure. Wanted to know how to appeal the way in which the committee structure was being set up. Set up a meeting on Friday Aug. 23 at 11:00.
21-Aug-02	Bert Hansen	Ben Arikawa	e-mail message	SDG&E, SCE and PG&E will participate in transmission owner classification and Mr. Hansen will be the representative.
21-Aug-02	Tony Braun	Ben Arikawa	e-mail message	Identifies representative from TANC as the CMUA nominee to stakeholder advisory committee
22-Aug-02	Ed Lucero	Ben Arikawa	e-mail message	Discussed issues that SDG&E wanted reviewed in GMC process.
22-Aug-02	Katie Kaplan	Ben Arikawa	e-mail message	Will be happy to participate in Generator class of advisory committee.
22-Aug-02	Ed Lucero		Phone call	SMD included in the GMC stakeholder process? Yes to some extent. What are services that ISO offers due to changes due to SMD? Need to understand what ISO does before allocation can take place. Need to return call and let him know what is on agenda for first
23-Aug-02	ISO Market Notice	Market participants	Market Notice	Outlined classes, requested nominations for representatives
23-Aug-02	Meeting with Rod Aoki		Meeting in SF	Met to discuss issues. Looking for possible compromises. Saw a need to lower level of hostility.
23-Aug-02	Meeting with Mirant		Meeting in Walnut Creek	Meeting to discuss what's going on with GMC. Steve raised issue with WPTF, but not a high priority issue.
26-Aug-02	ISO Market Notice	Market participants	Market Notice	Market Notice with proposed agenda and call in number for August 29, 2002 conference call on rate redesign process.
26-Aug-02	JingChao Mi		Phone call	GMC process questions. Told him that ISO was backing away from stakeholder advisory committee proposal. confusion over 2003 process and effect on 2003 GMC rates.
27-Aug-02	Jan Pritchard and Roger Van Hoy, John Springer and Ben Arikawa		meeting at Modesto	
28-Aug-02	David Cohen .		Phone call	Discussed purpose of conference call tomorrow. If this process slows down, it may imperil the settlement. How does MD02 proposal line up with SMD. Greenleaf (ID'ed for the job)
29-Aug-02			Conference call with interested parties	Conference call to discuss form that stakeholder process should take. At end of conference call, ISO and some participants agreed that stakeholder advisory committee would not adequately represent all interests. Participation by all parties was probably the way to go.
29-Aug-02	Rod Aoki	Ben Arikawa	e-mail message	Discuss potential steps in developing stakeholder process.

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Date	Person(s)	Recipient	Type	Description
29-Aug-02	Jan Pritchard		Phone call	Problem with stakeholder process. Sees no virtue in committee process. Will file a protest with ISO tomorrow that we are wasting our time.
29-Aug-02	Lisa Wolfe		Phone call	Satisfied? Useful that people had an opportunity to comment. But not much accomplished. No consensus about how to proceed. Nothing decided that helps us move forward. Tried to clarify what was said on the phone call on GMC stakeholder process. Tony Lam will be EOB staffer assigned to this. Lisa will be in Alaska Sept 11-20
29-Aug-02	Todd Edmister		Phone call	Agnostic, may not end up the way we want. Is okay with the process outlined on today's call.
30-Aug-02			Letter to Byron Woertz	MID comments on August 29, 2002 conference call with concerns about stakeholder advisory committee and process for reviewing proposals in the absence of a committee.
13-Sep-02	Jan Pritchard		Phone call	Discussed budget posting and GMC process. Will send out link or budget posting this afternoon if available.
13-Sep-02	Rod Aoki		Phone call	Discussed status of budget posting. Will send out link or posting this afternoon if it is available.
16-Sep-02	Laurence Kirsch	Ben Arikawa	e-mail message	Responded to e-mail message concerning MID's rate proposal.
16-Sep-02	Todd Edmister		Phone call	Discussed budget documents on website Will send a hardcopy.
16-Sep-02	Tony Lam		Phone call	Discussed budget posting on web. Will send a hard copy.
18-Sep-02	David Cohen		Phone call	Discussed meeting schedule. He wanted to know what was going on and when they would hear something. Confirmed for him that Public Budget meeting is still scheduled for Oct 4 9-12.
20-Sep-02	Laurence Kirsch	Ben Arikawa, Jan Pritchard, Sean Neal, Roger Van Hoy	e-mail message	Transmitted "Cookbook" on MID rate proposal.
20-Sep-02	David Cohen		Phone call	Discussed dates for meetings, agenda items, RTOWest. Other topics. Will send out a hardcopy of the budget document since some pages are unreadable. I should talk to active parties, CAC, CPUC, MID and IOUs.
20-Sep-02	Rod Aoki		Phone call	Discussed budget, budget presentation before board, schedule of budget meetings and schedule of GMC stakeholder meetings Didn't have a problem with ISO sending out the tasks (deliverables) list. Thought that it would make a good starting point for discussion about what needed to be done.
20-Sep-02	Tony Lam		Phone call	Discussed time of first meeting of GMC stakeholder meeting and other issues
23-Sep-02	Laurence Kirsch	Ben Arikawa	e-mail message	Response to ISO questions on MID rate proposal
23-Sep-02	Bert Hansen		Phone call	Budget meeting on Oct 8 am, Board teleconference Oct 11, Budget changes from public document less in fines and penalties available GMC stakehholder meetings Oct 9th - documents to be released

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23-Sep-02	Jan Pritchard		Phone call	Discussed Kirsch testimony and cookbook, and responses to my questions. Times and dates of GMC stakeholder meeting and budget meeting. Not interested in budget meeting, will let Cohen lead. Probably will need clarifications of definitions early on to prevent misunderstandings later. First reaction to agenda, criteria and task list was not favorable.
23-Sep-02	Jingchao Mi		Phone call	Changes in Budget since 9/13 public issuance Budget meeting possible on Oct 8 Board teleconference on Budget Oct 11, public discussion directly with Board GMC stakeholder meeting tentatively scheduled Oct. 9 Asked questions concerning budget terms and dollar flows Will talk to attorneys re: Board teleconference to decide what to say or write in written comments
23-Sep-02	Manuel Ramirez		Phone call	Discussed dates of GMC meeting, Budget meeting and Board teleconference. Talked about budget document, capital spending, need for 205 or info filing.
24-Sep-02	Ben Arikawa		e-mail message	Forwarded Ms. Le Vine's message to additional interested parties
24-Sep-02	Debi Le Vine	Market participants	e-mail message	E-mail message to Market Participants informing them of October 9, 2002 GMC rate redesign meeting. Attachments include proposed agenda, draft charter, possible tasks and possible evaluation criteria
24-Sep-02	Dave Arthur		Phone call	Left message re: Changes in Budget since 9/13 public issuance Budget meeting possible on Oct 8 Board teleconference on Budget Oct 11, public discussion directly with Board GMC stakeholder meeting tentatively scheduled Oct. 9
24-Sep-02	Debbie Dietz		Phone call	Left message□ Changes in Budget since 9/13 public issuance Budget meeting possible on Oct 8 Board teleconference on Budget Oct 11, public discussion directly with Board GMC stakeholder meeting tentatively scheduled Oct. 9
24-Sep-02	Ed Lucero		Phone call	Changes in Budget since 9/13 public issuance Budget meeting possible on Oct 8 Board teleconference on Budget Oct 11, public discussion directly with Board GMC stakeholder meeting tentatively scheduled Oct. 9 Interested in MD02 implementation and costs and how it affects GMC Some confusion over 2001 ID, 2002 Settlement, how they affect
24-Sep-02	Michele Wynne		Phone call	Changes in Budget since 9/13 public issuance Budget meeting possible on Oct 8 Board teleconference on Budget Oct 11, public discussion directly with Board GMC stakeholder meeting tentatively scheduled Oct. 9

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24-Sep-02	Shannon Black		Phone call	Changes in Budget since 9/13 public issuance Budget meeting possible on Oct 8 Board teleconference on Budget Oct 11, public discussion directly with Board GMC stakeholder meeting tentatively scheduled Oct. 9
26-Sep-02	ISO Market Notice	Market participants	Market Notice	Notice of October 9, 2002 meeting
30-Sep-02	Lisa Wolfe		Phone call	Discussed 2002 Settlement, EOB's request for ISO presentation of budget to EOB, schedule of budget meeting, stakeholder meeting and ISO Board teleconference on budget.
03-Oct-02	Karen Shea		Phone call	Discussed budget meeting for next week. Opportunity to comment on ISO budget before the Board on a teleconference. Wanted copies of benchmarking studies. Will send a request for public ones, I will send out the Alberta and IMO studies.
09-Oct-02	GMC WG		Stakeholder meeting at ISO	I. Introductions II. Approve Agenda III. Relevant Documents IV. 2003 GMC Update V. MD02 Update VI. General Issues a. Charter b. Schedule and Process c. Background Information d. Rate Design Criteria e. Rate Proposals f. Rate Proposal Review Process
11-Oct-02	Jan Pritchard		Phone call	Why didn't ISO post the letter on the ISO website? What went on during the meeting? How will MID disseminate its proposal and discussion? No call in number Who was there?
15-Oct-02	Ed Lucero		e-mail message	Discussed coordination to work on paper on rate design
18-Oct-02	JingChao Mi		Phone call	Questions about number of employees, amount of MD02 O&M vs. capital, and capital expenditures (graph in October 8 presentation did not match numbers in text of presentation).
21-Oct-02	Jan Pritchard	Various parties	e-mail message	Transmitted MID rate proposal in form of "cookbook"
22-Oct-02	Ed Lucero		Phone call	Talked about ratemaking: functionalize costs, classify services, assign costs to services, decide how to charge for services and assign charges to buckets.
23-Oct-02	Ben Arikawa	David Cohen, Ed Lucero	e-mail message	Distributed draft ratemaking methods paper to David Cohen and Ed Lucero
25-Oct-02	David Cohen	Ed Lucero, Ben Arikawa	e-mail message	Returned copy of ratemaking methods paper with edits

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Date	Person(s)	Recipient	Type	Description
25-Oct-02	Phil Leiber	Aoki , Rod; kth@cpuc.ca.gov; mzr@cpuc.ca.gov; Edmister, Todd; Neal, Sean; Shea, Karen; jalvidres@edisonmission.com; sfinch@edisonmission.com; Franklin, Brett; Wolfe, Lisa; palessandri@eob.ca.gov; Olsson, Ray; Lam, Tony; Kaplan, Katie; Jackson, Blair; Huhman, Steve; Cohen, David; Takehara, James; Yakin, Dale; schneider@rsvi.net; berton.hansen@sce.com; Lucero, Ed; Ryan, Mike; Mi, Jingchao; Zarafshar, Shahram; Pritchard, Jan	e-mail message	Transmitted copy of Ziad Alaywan's MD 02 presentation
25-Oct-02			note	GMC WG e-mail distribution list active
28-Oct-02	Ed Lucero	Ben Arikawa, David Cohen	e-mail message	Returned copy of ratemaking methods paper with edits
29-Oct-02	Ben Arikawa	David Cohen, Ed Lucero, Phil Leiber	e-mail message	Distributed updated ratemaking methods paper including Cohen and Lucero edits
05-Nov-02	Ben Arikawa	Ed Lucero, Bert Hansen, David Cohen	e-mail message	Responded to Ed's message about agenda for November 8 meeting
05-Nov-02	Debi Le Vine	GMC WG	e-mail message	Apologized for not getting notice of meeting out. Send out revised draft charter.
06-Nov-02	Debi Le Vine	GMC WG	e-mail message	Transmitted agenda for November 8 meeting
07-Nov-02	Phil Leiber	GMC WG	e-mail message	Distributed ISO rate comparison table
08-Nov-02	GMC WG		Stakeholder meeting at ISO	I. Introductions II. Approve Agenda III. MD02 Overview IV. Why ISO GMC is Not a Formula Rate V. Comparison of ISO Rate Structures VI. Presentation by Dr. Kirsch of MID Proposal VII. Summary of Ratemaking Methods
12-Nov-02	Ben Arikawa		MIF presentation	Discussed GMC Settlement, GMC filing and rate redesign
15-Nov-02	Karen Shea, Kirk Bracht		meeting at ISO	Discussed ISO GMC filing
02-Dec-02	Phil Leiber	GMC WG	e-mail message	Distributed agenda for December 9 meeting
02-Dec-02	Jan Pritchard		Phone call	Talked about agenda. Need for speed. Jan may ask for time at beginning of meeting to ask that people focus on getting rate design done. That it's separate from the costs.
03-Dec-02	Lisa Wolfe		Phone call	Discussed CPUC questions. Agenda for next GMC meeting and what the CPUC/EOB might propose as a rate structure.
04-Dec-02	Mike McGuffin, ISO	Jan Pritchard, MID	E-Mail Communication	E-mail message contains Ben Arikawa's request to Mike McGuffin to contact Jan Pritchard to discussion types of deviation data available from ISO.

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04-Dec-02	Jan Pritchard		Phone call	Discussed agenda for Monday meeting, list of items to be sent out to group. Jan sent a message re: FERC November 27th order. Will include the order and Spence's MD02 implementation schedule in the package sent out. Jan wanted to have parties speak to their issues, what they want in the rate design. List of items in package so far: data list list of services rate summaries FERC order 11/27/2002 Spence's presentation and memo Charter
04-Dec-02	Todd Edmister		Phone call	Discussed CPUC questions from last week: impact of MD02 implementation delay on costs and billing determinant for CONG. Todd asked if CONG rate is pancaked: flow from NP15 to ZP26 to SP15 gets charged twice for CONG. Didn't know. Will have answer later. Talked about what we will be sending out before meeting. Todd to talk to Karen Shea re: this conversation.
05-Dec-02	Jan Pritchard, MID	Mike McGuffin, ISO	E-Mail Communication	E-mail response of MID to above Mike McGuffin e-mail.
05-Dec-02	Phil Leiber	GMC WG	e-mail message	Distributed materials for December 9 meeting.
05-Dec-02	Rod Aoki		Phone call	Discussed agenda for Monday's meetings. What would be sent out. Asked him if they could discuss conceptually their proposal.
06-Dec-02	Ben Arikawa	GMC WG	e-mail message	Distributed presentations for December 9 meeting
09-Dec-02	Ben Arikawa	GMC WG	e-mail message	Outstanding issues from meeting and schedule for conference calls through rest of December
09-Dec-02	GMC WG		Stakeholder meeting at ISO	I. Introductions / Announcements II. Finalize Project Charter (timeline to be discussed at end of meeting) III. Statements on desirable rate design elements by parties developing proposals: MID, CPUC/EOB, CAC, etc IV. Briefing on ISO rate structure comparison V. Discussion of ISO List of Services Additions/Divisions/Deletions to be submitted to ISO by 12/31/02. ISO to provide indicative costs for each service by early February 2003 VI. Discussion of Data Necessary Distribute listing of anticipated data needs Additions to be submitted to ISO by 12/31/02. VII. Confidentiality issues VIII. MD02 Update IX. Discussion of upcoming (January) meeting agenda and overview of remaining steps
10-Dec-02	Stephen Morrison	GMC WG	e-mail message	Statement of ISO information availability policy
10-Dec-02	Susan Schneider	GMC WG	e-mail message	Clarified her earlier question on data confidentiality

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10-Dec-02	Jan Pritchard		Phone call	Jan left the meeting early. Discussed what went on after he left: data requirements, data confidentiality, and next steps, two conference calls. MID may hire a rate consultant, who will be on the calls. Maybe from Christensen and Associates.
10-Dec-02	Lisa Wolfe		Phone call	Call interrupted for a bit. Discussed intent of CPUC/EOB in inquiring about ETC costs.
11-Dec-02	Ben Arikawa	Dale Yakin	e-mail message	Response to questions asked at Dec. 9 meeting concerning MD02 activities
11-Dec-02	Dale Yakin	Ben Arikawa	e-mail message	Additional questions and clarifications based on earlier response
12-Dec-02	Ben Arikawa	GMC WG	e-mail message	Location of charge type matrix on ISO website
12-Dec-02	David Cohen	Ben Arikawa, Phil Leiber	e-mail message	Preliminary comments on provision of data and doing bill impact analysis
12-Dec-02	Dale Yakin		Phone call	Discussed my response to his email. Went through steps as I saw it. He's okay with that at this point.
12-Dec-02	Jan Pritchard		Phone call	RE: data conference call tomorrow. Ross Hemphill from Christensen and Associates was hired to work on MID's GMC issues.
13-Dec-02	GMC WG		Conference call	Discussion of billing determinants
13-Dec-02	Karen Shea	Ben Arikawa, Phil Leiber, Todd Edmister,Lisa Wolfe, Tony Lam	e-mail message	Preliminary data request
16-Dec-02	Ben Arikawa	David Cohen	e-mail message	Update ISO-NE rate information that David requested
16-Dec-02	Ben Arikawa	GMC WG	e-mail message	Distribution of revised list of billing determinants
16-Dec-02	Jan Pritchard		Phone call	Add Sean Neal to email distribution list. ETCs going down the wrong path. Laurence to work with Ross on data requirements. Puzzled by the use of activities list (not USOA, so difficult to understand what we are doing).
16-Dec-02	Lisa Wolfe		Phone call	Reviewed the data conference call from Friday, Dec 13. Discussed data that EOB might want, but didn't ask for. Reminder her about the Monday 23th conference call on activities.
17-Dec-02	Ben Arikawa	Jan Pritchard, Laurence Kirsch, Ross Hemphill, Phil Leiber, Stephen Morrison, Sean Neal	e-mail message	Compilation of notes on MID's data requirements
17-Dec-02	Ben Arikawa	Jan Pritchard, Laurence Kirsch, Ross Hemphill, Phil Leiber, Stephen Morrison, Sean Neal, Mike McGuffin	e-mail message	Communication detailing changes made in definitions of billing determinants data to reflect discussions with MID. Confirmation that net power withdrawals from ISO-controlled grid are equivalent to net control area load.
17-Dec-02	Laurence Kirsch, MID	Ben Arikawa,Jan Pritchard, Ross Hemphill, Phil Leiber, Stephen Morrison, Sean Neal	Memorandum	Dr. Kirsch provided revisions of billing determinant data descriptions and confirmed that net deviations described in above document met MID's definition of deviations. Also questioned if net control area load plus exports met MID's definition of net power withdrawals from ISO-controlled grid.
17-Dec-02	Jan Pritchard		Phone call	Data, see notes in note book. RE: data interpretation. will write email back to Jan, Laurence, Ross, Sean and Stephen to confirm interpretation
17-Dec-02	Rod Aoki		Phone call	Left message on voice mail. CAC working on proposal, trying to get together with CPUC/EOB to discuss it. Want demand charges. Also want SC specific information to develop the rate structure, but understand the need for confidentiality.

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19-Dec-02	Ross C. Hemphill	Ben Arikawa, ISO	E-Mail Communication and attached Word document	Dr. Hemphill criticized participants and ISO for inconsistent and inaccurate use of terminology. Dr. Hemphill suggested that the ISO use their rate consultants, Barkovich and Yap, to propose an "industry standard" structure for cost accounting for the ISO.
19-Dec-02	Ben Arikawa	GMC WG	e-mail message	Distributed documents for December 23 conference call
19-Dec-02	Stephen Morrison	GMC WG	e-mail message	Distributed first draft of Non-Disclosure Agreement
19-Dec-02	Jan Pritchard		Phone call	Sean having trouble with Stephen's concerns over data. Ross will send something over to me about activities.
20-Dec-02	Ben Arikawa	David Cohen	e-mail message	Sent spreadsheet that addressed David's questions about Statement AH
20-Dec-02	Lisa Wolfe	GMC WG, Stephen Morrison	e-mail message	Comments on confidentiality agreement
23-Dec-02	GMC WG		Conference call	Discussion of Confidentiality Agreement, groupings of activities, and data
23-Dec-02	Ben Arikawa	GMC WG	e-mail message	Distributed CAM documentation for conference call
23-Dec-02	Lisa Wolfe	GMC WG, Stephen Morrison	e-mail message	Additional comments on confidentiality agreement
23-Dec-02	David Cohen		Phone call	Discussed comments on Non-disclosure agreement. Asked about need for NDA for aggregate data. Talked about groupings of activities and cost centers. He did a assignment of costs to cost centers. Asked why we can't have FERC 900 account costs as customer charge. Wanted to know if ISO was planning a reorg because that would impact the activities, cost centers and assignments. Were startup costs just 1998-2000 bond recover? What about SC credit issue. If IOUs post credit, will that lead to possible upgrade of ISO rating? Did Steve Greenleaf ask FERC about the cost of MD02 and now the implementation required us to cash fund most of it
23-Dec-02	Karen Shea		Phone call	just some questions about docket # for GMC 2003 info filing. Mapping of cost centers to groupings. what is the call in number□
24-Dec-02	Ben Arikawa	Carolyn Kehrein	e-mail message	Description of ISO-NE rate structure
24-Dec-02	Lisa Wolfe	Various parties, not including Stephen Morrison	e-mail message	Agreement with Sean Neal's edits to confidentiality agreement
24-Dec-02	Jan Pritchard		Phone call	Discuss what went on during the conference call yesterday. He will tell Ross and Laurence to work within the process. Will get back to us about what they need.
24-Dec-02	Lisa Wolfe, Tony Lam, Brett Franklin, Patrick Alessandri		Phone call	Discussed what we are doing with the groupings of activities. How we will proceed with after agreement is reached on it. Discussed ETCs, some MD02 stuff.
31-Dec-02	JingChao Mi	Ben Arikawa, Phil Leiber	e-mail message	Transmitted CDWR comments on ISO groupings of activities and list of potential billing determinants
06-Jan-03	Ross C. Hemphill	Ben Arikawa, ISO	E-Mail Communication and attached Word document	Dr. Hemphill commented on the usefulness of the ISO's grouping of activities for MID's development of its rate proposal. Dr. Hemphill argued that the ISO should allocate its costs to the four functions proposed by MID.
06-Jan-03	Ben Arikawa	Jingchao Mi, GMC WG, Mike Werner, Peter Kissel	e-mail message	Thanked CDWR for its comments and discussed some of CDWR's issues
06-Jan-03	Jan Pritchard		Phone call	Ross's response. Jan will not be at next week's meeting.
06-Jan-03	JingChao Mi		Phone call	Discussed CDWR's comments. Clarified some. Will send out email response to the last comment on time period.

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07-Jan-03	Ben Arikawa	GMC WG	e-mail message	Responded to David Cohen questions. Cc'ed GMC WG
07-Jan-03	Todd Edmister and Karen Shea		Phone call	Discussed data request. Want us to set up conference call on what's wrong with data request. Set up for Thursday January 9 4-5.
08-Jan-03	ISO Market Notice	Market Participants	Market Notice	Notice of January 13 GMC meeting
08-Jan-03	Jingchao Mi		Phone call	Response to voicemail re: need to continue assignment of costs to activities groupings.
08-Jan-03	Lisa Wolfe		Phone call	Discussed CPUC conference call on data request. NDA for GMC data availability
09-Jan-03	Todd Edmister, Karen Shea, Phil Leiber, Stephen Morrison, Lisa Wolfe		conference call	Discuss how to respond to CPUC data request.
09-Jan-03	Ben Arikawa	GMC WG	e-mail message	Distributed agenda for January 13 meeting
09-Jan-03	Karen Shea	Phil Leiber, Ben Arikawa, GMC WG	e-mail message	Comments on GMC charter
09-Jan-03	Phil Leiber	Todd Edmister, Karen Shea, Lisa Wolfe	e-mail message	Response to question posed during conference call with CPUC
10-Jan-03	Ben Arikawa	GMC WG	e-mail message	Distributed agenda and documents for January 13 meeting
10-Jan-03	Lisa Wolfe	GMC WG	e-mail message	Additional comments on confidentiality agreement
10-Jan-03	Stephen Morrison	GMC WG	e-mail message	Revised draft of Confidentiality Agreement and Non-Disclosure Certificate distributed
13-Jan-03	Ben Arikawa	GMC WG e-mail distribution list	E-Mail Communication	ISO listed scheduling of MID/ISO conference call as an outstanding item from January 13th meeting
13-Jan-03	Ben Arikawa	Jan Pritchard, Ross Hemphill, and Laurence Kirsch, MID	E-Mail Communication	ISO proposed to hold a conference call with MID to discuss MID's concerns on functionalization.
13-Jan-03	Ben Arikawa	GMC WG	e-mail message	Distributed short presentation on functionalization
13-Jan-03	Ben Arikawa	GMC WG	e-mail message	Outstanding issues list from meeting
13-Jan-03	David Cohen	Ben Arikawa	e-mail message	Sent David's ISO-NE paper
13-Jan-03	Kyle Hoffman	GMC WG	e-mail message	Distributed presentation on ETC workload
13-Jan-03	GMC WG		Stakeholder meeting at ISO	I.Introductions /Announcements II.Distribute Final Project Charter III.Discussion of distribution of documents and communications and postings to GMC web page IV.Statements on desirable rate design elements by parties:MID,CPUC/EOB,CAC,CAISO,etc V.Break VI.Confidentiality issues/NDA VII.Discussion of data VIII.Lunch IX.Discussion of ISO list of activities X.Discussion of ETC workload XI.Summary of ISO-NE rate structure XII.Discussion of next steps
14-Jan-03	Ben Arikawa	Jan Pritchard	E-Mail Communication	ISO confirmed tentative time for conference call with MID for January 16th 9:30 to 11:00.

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14-Jan-03	Ben Arikawa	GMC WG	e-mail message	Distributed David Cohen's paper on ISO-NE rates and links to various pages and documents
14-Jan-03	Jan Pritchard		Phone call	Discussed times for conference call. Wants to know how ISO will proceed, if ISO assumes that MID will do work or that ISO is doing the work.
15-Jan-03	Ben Arikawa	GMC WG e-mail distribution list	E-Mail Communication	ISO confirmed time for conference call with MID for January 16th 9:30 to 11:00.
15-Jan-03	Jan Pritchard	Ben Arikawa	E-Mail Communication	MID asked for confirmation of time and date of conference call
15-Jan-03	Ben Arikawa	GMC WG	e-mail message	Forward of e-mail exchange between Kyle Hoffman and Brett Franklin of EOB
15-Jan-03	Ben Arikawa	Dale Yakin	e-mail message	Response to Jan 14 questions
15-Jan-03	Dale Yakin	Ben Arikawa	e-mail message	Follow-up questions to earlier e-mail
15-Jan-03	Kyle Hoffman	Brett Franklin;Wolfe, Lisa; Alessandri, Patrick; Lam, Tony; Leiber, Phil; Arikawa, Ben; Morrison, Stephen; Dozier, Mike	e-mail message	Response to Brett Franklin's questions on how the ETC workload was developed
15-Jan-03	Stephen Morrison	GMC WG	e-mail message	First NDA Register Update
15-Jan-03	Ben Arikawa		MIF presentation	Discussed GMC Settlement, GMC filing and rate redesign
15-Jan-03	Dale Yakin		Phone call	Information request, question about sending individual SC data.
15-Jan-03	Jan Pritchard		Phone call	Discussed lawyers' call (Settlement). Discussed time for MID/ISO call on data and development of MID proposal
16-Jan-03	MID, GMC WG		Conference call	MID data requirements and how to proceed
16-Jan-03	Phil Leiber	Jan Pritchard, Sean Neal, Ross Hemphill, and Laurence Kirsch, MID	E-Mail Communication with attachments	Transmittal of modified cost allocation matrix to MID, links to operational audit and SAS 70 report. Confirmation that ISO Board Budget Book was being sent via Federal Express. Documents and data sent as agreed to on conference call.
16-Jan-03	Ben Arikawa	GMC WG e-mail distribution list	e-mail message	Summary of discussion during conference call. Notes reviewed by MID prior to general distribution. ISO and MID agreed to distribution of interval level deviation subject to market notice. Also, the ISO would provide additional data and documentation to MID. (See below.) MID would prepare documentation (Statement BA) to better describe MID proposed functions. Next conference call scheduled for January 23rd, 9-11 am.
16-Jan-03	Ben Arikawa	GMC WG	e-mail message	Distribution of aggregated monthly billing determinants
16-Jan-03	ISO Market Notice	Market Participants	Market Notice	Notice that ISO intends to distribute SC-related data in GMC project
16-Jan-03	Jan Pritchard		Phone call	Discussed response to conference call. Talked about my summary of meeting.
17-Jan-03	Ben Arikawa	Dale Yakin, GMC WG	e-mail message	Response to follow-up questions from Jan. 15
17-Jan-03	Stephen Morrison	GMC WG	e-mail message	ISO response to 12/13/2002 CPUC/EOB data request
17-Jan-03	Dale Yakin		Phone call	Discussed meeting at PG&E potential. Discussed questions that Dale posed earlier in the week.
21-Jan-03	Ross Hemphill	Ben Arikawa	E-Mail Communication with attachments	MID transmits Statement BA to ISO with descriptions of rate functions.
21-Jan-03	Ben Arikawa	GMC WG	e-mail message	Checking off list of outstanding issues from January 13 meeting

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22-Jan-03	Ben Arikawa	Jan Pritchard, Laurence Kirsch and Ross Hemphill	E-Mail Communication	ISO transmittal of agenda to MID. Agenda had been modified during a telephone discussion between Ben Arikawa and Ross Hemphill.
22-Jan-03	Ben Arikawa	GMC WG e-mail distribution list	E-Mail Communication with attachments	ISO transmittal of conference call information, agenda and MID's Statement BA to participants
22-Jan-03	Jan Pritchard		Phone call	Agenda for Thursday morning meeting.
23-Jan-03	MID, GMC WG		Conference call	Conference call with MID, open to all participants in 2004 GMC Rate Structure project
23-Jan-03	Phil Leiber	Jan Pritchard, Sean Neal, Ross Hemphill, and Laurence Kirsch, MID	E-mail communication	Confirmation that ISO will make available two directors from Grid Operations to answer questions. ISO provided these directors' schedules.
23-Jan-03	Ben Arikawa	GMC WG	e-mail message	Notice of February 19 meeting at PG&E
23-Jan-03	Ben Arikawa	Karen Shea, Todd Edmister, Phil Leiber, Stephen Morrison	e-mail message	Retransmitted Jan 10th e-mail sent by Mr. Leiber. Board Budget Book is confidential and cannot be distributed without a NDC in
23-Jan-03	Karen Shea	Ben Arikawa	e-mail message	Request for documents distributed to MID
23-Jan-03	Phil Leiber	David Hawkins and Deane Lyon	Internal ISO e-mail communication	Notice to Grid Operations directors that MID requires their assistance in developing cost assignments.
24-Jan-03	Ben Arikawa	GMC WG e-mail distribution list	E-Mail Communication	Notice of conference call with call in information
24-Jan-03	Ben Arikawa	Jan Pritchard, Laurence Kirsch and Ross Hemphill	E-Mail Communication with attachments	ISO transmittal of draft meeting notes to MID for review
24-Jan-03	Jan Pritchard		Phone call	Redux of conference call.
27-Jan-03	Laurence Kirsch	Ben Arikawa, Jan Pritchard, Sean Neal and Ross Hemphill	E-Mail Communication with attachments	MID markup of meeting notes
28-Jan-03	Ben Arikawa	GMC WG e-mail distribution list	E-Mail Communication with attachments	Transmittal of January 23rd meeting notes to participants in 2004 GMC Rate Structure Project
28-Jan-03	Ben Arikawa	Jan Pritchard, Laurence Kirsch and Ross Hemphill	E-Mail Communication with attachments	Transmittal of additional detail of bond-financed capital expenditures and a description of activities included in ASREO function.
28-Jan-03	Laurence Kirsch	Ben Arikawa	E-Mail Communication with attachments	Transmittal of spreadsheet detailing preliminary functional assignments and document discussing how assignments were made and where additional information was needed.
28-Jan-03	Ross Hemphill		Phone call	Discussed capital spending allocations in modified CAM. Will send capital spreadsheet to him if possible after checking with Phil and Stephen.
29-Jan-03	Ben Arikawa	Laurence Kirsch, Ross Hemphill, Jan Pritchard	E-Mail Communication	Request for agenda items for January 30th conference call
29-Jan-03	Laurence Kirsch	Ben Arikawa	E-Mail Communication	Response of Dr. Kirsch to request for agenda items.
29-Jan-03	Ross Hemphill	Ben Arikawa, Jan Pritchard, Laurence Kirsch	E-Mail Communication	Transmittal of proposed agenda for next ISO/MID conference call scheduled for January 30th.
29-Jan-03	Ben Arikawa	GMC WG distribution list	E-Mail Communication with attachments	Transmittal to participants of non-confidential documents sent to MID, notification of confidential documents sent, notice of call in number and agenda for MID/ISO January 30th conference call.

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29-Jan-03	Jan Pritchard		Phone call	agenda for conference call tomorrow.
30-Jan-03	MID, GMC WG		Conference call	MID data requirements and how to proceed
30-Jan-03	MID, GMC WG		Conference call	Conference call between MID and ISO, open to all participants.
30-Jan-03	Ross Hemphill	Ben Arikawa	E-Mail Communication	As discussed during the conference call, MID transmitted schedules of Drs. Kirsch and Hemphill
30-Jan-03	Ben Arikawa	David Cohen	e-mail message	Sent spreadsheet requested and will send CD with deviation data
31-Jan-03	Ross Hemphill	Ben Arikawa	E-Mail Communication	Reviewed meeting notes with minor changes.
31-Jan-03	Ben Arikawa	GMC WG distribution list	E-Mail Communication with attachments	Transmittal of non-confidential data and MID/ISO conference call notes.
31-Jan-03	Ben Arikawa	Laurence Kirsch, Ross Hemphill, Jan Pritchard	E-Mail Communication with attachments	Transmittal of draft meeting notes to MID for review. Confirmation that ISO is prepared to discuss Grid Operations activities on February 3rd.
31-Jan-03	Ben Arikawa	Jingchao Mi	e-mail message	Transmitted confidential documents requested by phone
31-Jan-03	Ben Arikawa	Keith Casey, Jan Cogdill, Bruce Drummond, Kyle Hoffman, Eric Leuze, Ali Miremadi, David Hawkins, Deane Lyon,	Internal e-mail Communication	Invitation to staff to listen in on first MID/ISO conference call on Grid Operations activities
31-Jan-03	Ben Arikawa	Michelle Gamble	Internal e-mail Communication	Request to schedule conferences with relevant staff and MID
31-Jan-03	Ben Arikawa	Keith Casey, Jan Cogdill, Bruce Drummond, Kyle Hoffman, Eric Leuze, Ali Miremadi, David Hawkins, Deane Lyon,	Internal e-mail Communication with attachments	Transmittal of relevant documents to prepare ISO staff for conference calls with MID.
31-Jan-03	Jingchao Mi		Phone call	Requested confidential documents referred to in Thursday's conference call. Sent electronic copies of modified CAM, bond financed capital spreadsheet and fed-ex'ed copies of Board Budget Book to Jingchao and Harrison Call.
31-Jan-03	Ross Hemphill		Phone call	Discuss conference calls for next week. I will try to get them scheduled for Tuesday-Thursday, 2 each day, one morning, one afternoon.
03-Feb-03	ISO, MID, GMC WG		Conference call	Conference call between ISO and MID concerning Grid Operations activities
03-Feb-03	Ben Arikawa	GMC WG e-mail distribution list	E-Mail Communication	Brief report of results of conference call with MID. Call in information for February 4th conference call on capital expenditures and bond financing.
03-Feb-03	Phil Leiber	Ross Hemphill, Laurence Kirsch, Jan Pritchard	E-Mail Communication	Transmittal of market notice of 2002 PwC Operational Audit results
03-Feb-03	Ben Arikawa	Laurence Kirsch	E-mail communication	Review of consistency of results. Pointing to potential error.
03-Feb-03	Laurence Kirsch	Ben Arikawa	E-Mail Communication with attachments	Dr. Kirsch confirms that there is mistake in cost assignment for RMR software. Updated cost assignment spreadsheet is sent.

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03-Feb-03	Laurence Kirsch	Ben Arikawa, David Hawkins	E-Mail Communication with attachments	Transmittal of changes as a result of conversation between ISO and MID on Grid Operations.
03-Feb-03	Ben Arikawa	Postar, Mike; Griess, Bryan; Neal, Sean; Leiber, Phil; Morrison, Stephen; Pritchard, Jan; David Cohen	e-mail message	Responded David's earlier e-mail message asking that some tracking of the changes in MID's cost allocations be done. Listed the conference calls scheduled with MID
03-Feb-03	Phil Leiber	GMC WG	e-mail message	Additional information for MID
04-Feb-03	ISO, MID, GMC WG		Conference call	Conference call with MID and ISO on bond financed and capital expenditures
04-Feb-03	Phil Leiber	GMC WG e-mail distribution list	E-Mail Communication	Summary of conference call on bond financing and capital expenditures and call information for next conference call.
04-Feb-03	Phil Leiber	Laurence Kirsch, Ross Hemphill, Jan Pritchard, Sean Neal	E-Mail Communication and attachment	Additional information concerning capital expenditures on software systems and their assignment to functions.
04-Feb-03	Bert Hansen	Ben Arikawa	e-mail message	Transmitted SCE proposal to ISO
05-Feb-03	ISO, MID, GMC WG		Conference call	Conference call with MID and ISO staff on activities in Market Analysis and Compliance
05-Feb-03	Ben Arikawa	GMC WG e-mail distribution list, Keith Casey, Eric Leuze	E-mail Communication	Summary of conference call with MID and ISO staff on Market Analysis and Compliance activities
05-Feb-03	Laurence Kirsch	Ben Arikawa	E-Mail Communication with attachments	Transmittal of updated spreadsheet to ISO by MID
05-Feb-03	Phil Leiber	GMC WG	e-mail message	Concerning customer classes
05-Feb-03	Ben Arikawa	Greta Ossman, Bruce Drummond, Ali Miremadi, Kyle Hoffman, Eric Leuze, Jan	Internal e-mail Communication	Transmittal of revised MID spreadsheet to ISO staff for review.
06-Feb-03	Ben Arikawa	Jan Pritchard, Laurence Kirsch, Ross Hemphill	E-Mail Communication	ISO requests feedback on MID views on progress of conference calls.
06-Feb-03	ISO Market Notice	Market Participants	Market Notice	Notice of February 19 meeting at PG&E
06-Feb-03	Jan Pritchard		Phone call	How are conferences doing? Getting good reports from Laurence and Ross.
06-Feb-03	Tony Lam		Phone call	Status of EOB/CPUC rate proposal? Ability of PTOs to pass through ETC charges.
06-Feb-03	Jingchao Mi	Ben Arikawa	Phone call and e-mail message	Why do we need customer classes? Market notice?
07-Feb-03	ISO, MID, GMC WG		Conference call	MID call with Information Services
07-Feb-03	Ben Arikawa	GMC WG	e-mail message	Distributed GMC briefing notes
07-Feb-03	Jingchao Mi	Ben Arikawa	e-mail message	Resent CDWR's view on groupings of activities
07-Feb-03	Jan Pritchard		Phone call	RE: response to e-mail on are you happy yet?
07-Feb-03	Jingchao Mi		Phone call	What is ISO proposal? Is there is a written document on it? Conversation w/CPUC - Karen Shea
07-Feb-03	Jingchao Mi		Phone call	Discussed Mike's email to me. CDWR's comments on groupings of activities.
08-Feb-03	Karen Shea	Phil Leiber, Ben Arikawa, GMC WG	e-mail message	CPUC comments on SC groupings and ETCs

Attachment 2 - Stakeholder Process Contacts

Date	Person(s)	Recipient	Type	Description
10-Feb-03	ISO, MID, GMC WG		Conference call	Conference call with MID and ISO staff concerning Market Services activities
10-Feb-03	Laurence Kirsch	Ben Arikawa	E-Mail Communication	Communication regarding activities in cost center 1723
10-Feb-03	David Cohen	Postar, Mike; Griess, Bryan; Leiber, Phil; Ben Arikawa	e-mail message	Asked that ISO look into more direct assignment of $60 million in indirect assignments.
10-Feb-03	Laurence Kirsch		Phone call	Confirmed my earlier voicemail message concerning Oracle licenses. Will attempt to set up a call with Debi on 1731
11-Feb-03	Ben Arikawa	GMC WG	e-mail message	GMC discussion boards are functional
11-Feb-03	Ben Arikawa	GMC WG	e-mail message	Response to Dale Yakin questions about analysis tool. ISO will put together a GMC Tool.
11-Feb-03	David Cohen	Postar, Mike; Griess, Bryan; Ben Arikawa	e-mail message	Posed a few questions and suggestions for moving forward. Asked that ISO make a short presentation on ISO Budget Tool on Feb. 19
11-Feb-03	Leslie Pompel	Ben Arikawa	e-mail message	Last message in exchange between Leslie and Ben Arikawa on how to make comments and express concerns about proposals given that BPA would not be attending in person.
12-Feb-03	Ben Arikawa	Laurence Kirsch	E-Mail Communication	Transmittal of revised cost allocation matrix and documentation on cost centers 1424 and 1441 provided under the Non-Disclosure
12-Feb-03	Ben Arikawa	David Cohen; GMC WG	e-mail message	Response to David's Feb. 11 e-mail on status of GMC Tool
12-Feb-03	Ben Arikawa	GMC WG	e-mail message	Notice of availability of confidential information sent to MID
12-Feb-03	David Cohen	Postar, Mike; Griess, Bryan; Leiber, Phil; Ben Arikawa	e-mail message	Asked that ETC definition be added to ETC spreadsheet sent out by Phil Leiber
12-Feb-03	Phil Leiber	GMC WG	e-mail message	Analysis of MD02 and ETCs
13-Feb-03	Ben Arikawa	Lisa Wolfe	e-mail message	Transmitted CAM used by MID as of February 7, 2003
13-Feb-03	Jingchao Mi	Edna Walz (E-mail); Elisa J. Grammer (E-mail); Harrison Call Jr. (E-mail 2); Harrison Call Jr. (E-mail); Peter Kissel (E-mail); Terry, Lee; Werner, Michael, Ben Arikawa	e-mail message	CDWR comments on customer classes
13-Feb-03	Karen Shea	Phil Leiber, Ben Arikawa, GMC WG	e-mail message	Comments on Ziad Alaywan's presentation at the MIF. Questions about composition of schedules
13-Feb-03	James Farrrar		Phone call	Confidentiality agreement and NDA, who to send it to?
13-Feb-03	Jingchao Mi		Phone call	Discussed CDWR's memorandum concerning customer classes and getting to Feb 19th meeting.
14-Feb-03	Ben Arikawa	GMC WG e-mail distribution list	E-Mail Communication with attachments	Transmittal of various documents in preparation for February 19th GMC meeting. Includes a brief summary of conference calls held with MID regarding activities in ISO cost centers
14-Feb-03	Jingchao Mi		Phone call	Discussed CDWR memo of yesterday. May have a CDWR proposal on Monday.
18-Feb-03	Ben Arikawa	GMC WG	e-mail message	Additional documents for February meeting
18-Feb-03	David Cohen		Phone call	Discussed MID proposal, CPUC's ETC fixation, Indirects on agenda. billing determinants - ETCs that are no longer ETCs should be excluded
18-Feb-03	Jingchao Mi		Phone call	Agenda for Wednesday meeting, groupings of activities

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Date	Person(s)	Recipient	Type	Description
19-Feb-03	GMC WG		Stakeholder meeting at PG&E	Introductions/Announcements Edison Rate Proposal Break MID Rate Proposal GMC Tool Prototype Lunch ISO Conceptual Rate Proposal Discussion of billing determinants Discussion of grouping of activities Break Review of MID/ISO conference calls Mapping of SC IDs to customer classes Budget Tool Miscellaneous Items (Discussion of indirect assignments,public discussion page on ISO GMC web page,follow-up conference calls,next meeting)
21-Feb-03	Ben Arikawa	Laurence Kirsch, Jan Pritchard	E-Mail Communication	Follow-up to ensure that MID had sufficient information from ISO concerning cost center 1731.
21-Feb-03	Laurence Kirsch	Ben Arikawa	E-Mail Communication	Confirmation that MID had received sufficient information to complete its cost assignment of cost center 1731
21-Feb-03	Ben Arikawa	GMC WG	e-mail message	Notice that SCE has posted on discussion board
21-Feb-03	Ben Arikawa	GMC WG	e-mail message	Distributed draft meeting notes
21-Feb-03	Phil Leiber	Karen Shea	e-mail message	Discussed SC "classes" and the ISO and stakeholder objections to them. Provided CPUC with a spreadsheet containing SC listing and previous classification
21-Feb-03	Jan Pritchard		Phone call	How did I think meeting went. Billing determinants.
25-Feb-03	Lisa Wolfe		Phone call	? Time indeterminate. Discussed EOB/CPUC proposal.
26-Feb-03	Jan Pritchard		Phone call	Discussed meeting on March 4th. Doesn't have a problem if the meeting is postponed.
26-Feb-03	Tony Lam		Phone call	Discussed status of EOB/CPUC proposal. ISO proposal and its status.
27-Feb-03	Phil Leiber	Karen Shea, Ben Arikawa	e-mail message	Response to voicemail re: outstanding ISO debt
28-Feb-03	Ben Arikawa	Jan Pritchard, Bert Hansen	E-Mail Communication	Confirmation that MID and SCE would be available for the scheduled March 4, 2003 conference call to discuss rate proposals
28-Feb-03	Ben Arikawa	GMC WG	e-mail message	Notice of March 4 conference call
28-Feb-03	Jingchao Mi	Ben Arikawa, Peter Kissel	e-mail message	Additional comments on customer classes
28-Feb-03	Dale Yakin		Phone call	Discussed Dale's question re: stranded costs. Reminded him of the conference call on Tuesday.
28-Feb-03	Jingchao Mi		Phone call	Discussed Karen Shea's customer classes request. "cost-shifting." ISO position on that. What was the agenda for the Tuesday conference call.
28-Feb-03	Tony Lam		Phone call	Gross vs. net billing determinant. How that would apply to MSS, generation and load at same bus. Could IOU form MSS to get advantage of netting?
03-Mar-03	Ben Arikawa	GMC WG e-mail distribution list	E-Mail Communication with attachments	Transmittal of MID "GMC Rate Design" paper to participants, URLs of additional meeting documents and February 19, 2003 meeting notes.

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03-Mar-03	Laurence Kirsch	Ben Arikawa, Phil Leiber, Jan Pritchard, Ross Hemphill	E-Mail Communication with attachments	Transmittal of MID modified Cost Allocation Matrix and MID "GMC Rate Design" paper for discussion on March 4, 2003 conference call.
03-Mar-03	Ben Arikawa	GMC WG	e-mail message	Agenda for March 4 conference call and additional documents describing MID and SCE proposals
04-Mar-03	GMC WG		Conference Call	Introductions/Announcements Follow-up discussion of rate proposals Assistance required by proponents Clean-up issues from February 19 meeting (Discussion of indirect assignments,public discussion page,preparation for next meeting)
04-Mar-03	Lisa Wolfe	GMC WG	e-mail message	EOB comments on customer class development
04-Mar-03	Lisa Wolfe		Phone call	Phone call response to Lisa Wolfe's voice mail to me. CPUC/EOB issue - customer classes. What was mentioned on the conference call. Discussion of equal treatment of similarly situated parties, how does the ISO measure load to get net.
05-Mar-03	Ben Arikawa	EOB (Lisa Wolfe, Tony Lam, Brett Franklin, Patrick Alessandri, Ray Olsson), PG&E (Dale Yakin), Navigant (David Cohen), CAC/EPUC (Rod Aoki, Don Schoenbeck, Jim Ross), CDWR (Jingchao Mi, Peter Kissel)	E-Mail Communication with attachments	Distribution of MID modified Cost Allocation Matrix to parties that requested a copy and that were covered by Non-disclosure Certificate (in separate messages)
05-Mar-03	David Cohen		Phone call	Outstanding items: More direct attribution of indirects Can we look at Budget Tool at ISO GMC Tool compare cost assignments of different proposals Make a deal with Edison on Mohave CPUC confidentiality NCP, CP argument with CDWR (how will it pan out) Concern about CPUC - haven't fully articulated that wholesale ETCs are under MSS. What's the magnitude of ETC costs? What does MSS cost? Effect on GMC, tariff? Discussed double-charging of load following Need to identify meeting dates soon. Need 3 or 4 meetings in April-May? Willing to have back to back meetings. Need Bill impacts, test sensitivity of moving assignments in CAM on MID/ISO proposals
05-Mar-03	Tony Lam		Phone call	Discussed errors in aggregated data spreadsheet, need to inform MID of updated deviation #s. What was discussed on March 4th conference call.
06-Mar-03	Ben Arikawa	Bert Hansen	e-mail message	Send Bert information previously sent to MID: CAM, Board Budget Book, various ancillary spreadsheets.
06-Mar-03	Jingchao Mi	Ben Arikawa	e-mail message	Electronic copy of comments provided at February 19, 2003 GMC meeting

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06-Mar-03	Bert Hansen		Phone call	Asked Bert what he needed from us. Agreed to sent out the information sent to MID in putting their proposal together.
06-Mar-03	Jan Pritchard		Phone call	Asked if there was anything that ISO owed MID to assist in development of its rate proposal. Nothing specific.
07-Mar-03	Ben Arikawa	GMC WG	e-mail message	Distributed GMC briefing notes and documents
07-Mar-03	Tony Lam		Phone call	Discuss of netting for MSS. How CRS is determined. Will EOB have a proposal? Yes, conference call is fine with EOB. Why do munis get to net behind the meter generation when PG&E in SF could not? What is special about MSS agreements and GMC?
10-Mar-03	Laurence Kirsch	Stephen Morrison, Sean Neal, Jan Pritchard	E-Mail Communication with attachments	Transmittal of revised "GMC Rate Design" paper
11-Mar-03	Ben Arikawa	Jan Pritchard, Laurence Kirsch, Ross Hemphill	E-Mail Communication	Informing MID that Ben Arikawa will make a Market Issues Forum presentation on the status of the 2004 GMC Rate Structure Project. Included will be a discussion of each of the rate proposals before the participants.
11-Mar-03	Jan Pritchard	Ben Arikawa, Sean Neal, Laurence Kirsch, Ross Hemphill, Mike Kreamer, Roger Van Hoy	E-Mail Communication	Request that ISO inform MIF attendees of availability of MID proposal and encourage attendees to participate on March 17, 2003 conference call.
11-Mar-03	Phil Leiber	Karen Shea, GMC WG	e-mail message	Response to Feb. 8th questions from the CPUC
11-Mar-03	Bert Hansen		Phone call	Discussed ISO proposal. He had lost his notes on it from the March 4th conference call. Informed him that I am going to make presentation at MIF meeting on GMC project and will present sketch of SCE proposal.
11-Mar-03	Jan Pritchard		Phone call	Discussed next meeting or conference call. Nothing likely to come out from ISO or Edison prior to March 17th.
12-Mar-03	Ben Arikawa	Sean Neal, Laurence Kirsch, Ross Hemphill, Mike Kreamer, Roger Van Hoy, Stephen Morrison, Phil Leiber	E-Mail Communication	Response to MID request confirming that ISO will give URL of 2004 GMC Rate Structure Project documents and will post the MID "GMC Rate Design" paper as soon as confidentiality of the document is reviewed
12-Mar-03	Ben Arikawa	Sean Neal, Laurence Kirsch, Ross Hemphill, Mike Kreamer, Roger Van Hoy, Stephen Morrison, Phil Leiber	E-Mail Communication	URL of ISO MIF presentation on status of GMC Rate Structure Project
12-Mar-03	Ben Arikawa	Sean Neal, Laurence Kirsch, Ross Hemphill, Mike Kreamer, Roger Van Hoy, Stephen Morrison, Phil Leiber	E-Mail Communication	Updated URL of ISO MIF presentation on status of GMC Rate Structure Project
12-Mar-03	Karen Shea	Ben Arikawa, Phil Leiber, Todd Edmister,Lisa Wolfe, Tony Lam	e-mail message	Response to notice of conference call time, questions re: MD02 and ETCs
13-Mar-03	Ben Arikawa	GMC WG e-mail distribution list	E-Mail Communication with attachments	Transmittal of proposed March 17, 2003 conference call agenda and latest version of MID "GMC Rate Design" paper
13-Mar-03	Ben Arikawa		MIF presentation	Presentation describing status of 2004 GMC Rate Structure Project and the three rate proposals (including MID's) under consideration.
14-Mar-03	Phil Leiber	GMC WG	e-mail message	Distributed presentation on ISO proposal

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17-Mar-03	GMC WG		Conference call	Introductions/Announcements CPUC/EOB Issues Follow-up discussion of rate proposals SCE MID ISO Other issues Discussion of indirect cost assignments GMC Tool Status Confidentiality of MID document Update on public and private discussion sites Next meeting(s)
19-Mar-03	Jan Pritchard		Phone call	Discussed GMC matters. Status of ISO proposal, what Karen Shea was asking on Monday conference call.
23-Mar-03	Karen Shea	Phil Leiber, 'GMC WG; Edmister, Todd; Arikawa, Ben; Wolfe, Lisa; Lam, Tony; Alaywan, Ziad; 'david.lengenfelder@ferc.gov'; Shea, Karen M.; "Iklé, Judith C."	e-mail message	Comments and questions about ISO GMC proposal and billing determinants
24-Mar-03	Ben Arikawa	GMC WG e-mail	E-Mail Communication with attachments	Distribution of March 17, 2003 conference call notes
24-Mar-03	Phil Leiber	Karen Shea; GMC WG; Edmister, Todd; Arikawa, Ben; Wolfe, Lisa; Lam, Tony; Alaywan, Ziad; Lengenfelder, David; "Iklé, Judith C."	e-mail message	ISO response to Karen Shea's questions and comments of March 23
24-Mar-03	Tony Lam		Phone call	Discussed Karen Shea e-mail of Sunday 23rd. Where did attachments come from?
26-Mar-03	Dale Yakin		Phone call	Discussed PG&E's view on ISO proposal - looks okay conceptually, but need #s Discussed CPUC quest to charge ETCs separately. Dale thinks PG&E would be against it. An additional cost that they don't want to deal with under the bankruptcy. May have heavy hitters at April meeting to talk about this and other things.
27-Mar-03	Ben Arikawa	GMC WG	e-mail message	Distributed GMC briefing notes
27-Mar-03	Ben Arikawa	GMC WG	e-mail message	Notice of conference call with SCE on April 2
27-Mar-03	Bert Hansen		Phone call	Return call from Bert. Discussed SCE's need for assistance on their rate proposal. Set Wednesday April 2 9:30-11:00 as a conference call.

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27-Mar-03	Bert Hansen		Phone call	Discussed Cohen's proposal that SCE negotiate with ISO on DDES charge (or an exemption for Mohave). ISO cannot be proponent of the proposal. SCE needs to push it to participants itself. Bert understands this and is working on memo and will send out something to GMC WG on this. Conference call time moved to 9:00 am on April 2 due to fire drill at SCE.
31-Mar-03	Jan Pritchard		Phone call	Discussed topics of April 2 conference call. Asked for RSVP for April 11 meeting (3 coming). Discussed DDES charge and what it might apply to.
31-Mar-03	Rod Aoki		Phone call	Asked number of people coming to ISO on April 11. 2 - Rod and Jim Ross or Don Schoenbeck Asked if CAC/EPUC would consider a proxy for QF behind the meter connected load that would be easily available to the ISO for use in calculating rates.
01-Apr-03	Bert Hansen		e-mail message	Explanation of DDES charge, why SCE thinks that it is reasonable
01-Apr-03	Ben Arikawa	GMC WG	Posting to public discussion board	ISO posts SCE explanation of DDES charge to public discussion board
02-Apr-03	GMC WG		Conference call	Introductions/roll call Discussion of SCE conceptual rate proposal Dynamic Dispatch Export Service Control Area Services Scheduling Service Market Operations Services Real Time Market Operations Service ISO Assistance
02-Apr-03	Ben Arikawa	GMC WG	e-mail message	Distributed GMC briefing notes
03-Apr-03	Ben Arikawa	GMC WG	e-mail message	Distributed draft notes of conference call with SCE
03-Apr-03	ISO Market Notice	Market Participants	Market Notice	Notice of April 11 meeting
04-Apr-03	Ben Arikawa	GMC WG	e-mail message	Distributed briefing notes
04-Apr-03	Jan Pritchard		Phone call	Discussion of agenda for April 11th meeting. Attendees from MID - 3
07-Apr-03	Ben Arikawa	Bert Hansen	e-mail message	Transmitted MID cost assignments and blank template for Bert to
07-Apr-03	Ben Arikawa	Bert Hansen	e-mail message	Transmitted modified CAM for Bert to work with
07-Apr-03	Ben Arikawa	Bert Hansen	e-mail message	Transmitted contact information for Grid Ops and Finance and Accounting
07-Apr-03	Ben Arikawa	GMC WG	e-mail message	Notice that modified CAM is available on confidential discussion board
07-Apr-03	Ben Arikawa	Lyon, Deane; Hawkins, David (CAISO); McClain, Jim; Le Vine, Debi; McGuffin, Mike; Timson, David; Leiber, Phil; Cogdill, Jan; Drummond, Bruce; Ossman, Greta; Casey, Keith; Leuze, Eric; Alaywan, Ziad	e-mail message	Informed staff of need to assist SCE and that SCE will call them directly if there is a question
08-Apr-03	Jing Chao Mi		Phone call	RVSP. 2 that he knows of. Discussed use of NCP vs. CP. What is the cost justification. What is diversity. Why is CDWR different than other SCs.

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08-Apr-03	Kevin Smith		Phone call	Wanted to get up to date with GMC process. What documents he needed. Wants to have lunch tomorrow if his schedule permits to catch up.
08-Apr-03	Tony Lam		Phone call	RSVP people Tony and Karen. Logistics for meeting. Move EOB/CPUC agenda item later near ISO. Who will be new attorney on EOB.
09-Apr-03	Ben Arikawa	Bert Hansen	e-mail message	Transmitted full list of contact information for Grid Ops, Finance and Accounting, Market Services, Information Services, Market Analysis and Compliance
09-Apr-03	Ben Arikawa	GMC WG	e-mail message	Transmitted ISO rate proposal white paper and appendices
09-Apr-03	David Cohen		Phone call	What is in Bert Hansen's matrix? What will the ISO be giving out today and on Friday? Is there an agenda for Friday's meeting? Can we have hardcopies of the CAM available Friday for him and others to peruse?
10-Apr-03	Laurence Kirsch	Ben Arikawa	E-Mail Communication with attachments	Laurence Kirsch's presentation for the April 11, 2003 GMC meeting
10-Apr-03	Ben Arikawa	GMC WG	e-mail message	Distributed Dr. Kirsch's presentation
10-Apr-03	Ben Arikawa	GMC WG	e-mail message	Distributed CPUC/EOB presentation
10-Apr-03	Tony Lam	Ben Arikawa, Jeff Slaton, Karen Shea	e-mail message	Transmitted CPUC/EOB proposed modifications to ISO GMC rate proposal
10-Apr-03	Jan Pritchard		Phone call	Please provide Kirsch's presentation today if at all possible. Discussed ISO proposal. Was disappointed that 40 percent of ISO costs were recovered through Gross Load. discussed ETCs
11-Apr-03	GMC WG		Stakeholder meeting at ISO	1.Introductions/roll call 2.Discussion of SCE rate proposal 4.CPUC/EOB update 5.MID proposal update 5.Discussion of ISO rate proposal 6.Discussion of remaining timeline to include: Customer impact analysis Evaluation of proposals Positions of parties
15-Apr-03	Laurence Kirsch	Ben Arikawa, Debi Le Vine, Phil Leiber, Jan Pritchard, Sean Neal and Ross Hemphill	E-Mail Communication	Questions posed by Dr. Kirsch at the end of the April 11, 2003 GMC meeting

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15-Apr-03	Bert Hansen	Ben Arikawa	e-mail message	Asked clarifying questions concerning billing determinants
17-Apr-03	Bert Hansen		Phone call	Discussed his April 15th email requesting info on self-provided AS and the calculation of the billing units for SCE's Market Operations charge. Told him that self provided AS is about 25 percent of non-self provided AS
17-Apr-03	Bert Hansen		Phone call	Gave him 17,000,000 MWhs as an approximate number for non-self provided AS.
17-Apr-03	Dale Yakin		Phone call	Discussed questions about billing determinant data. re: Dale's April 14th email to me. Initial reaction from PG&E was not bad. Need to see impact on PG&E. Still thinks that MID proposal is lacking some things. doesn't account for safety, some aspects of grid management. SCE proposal seems fair. DDES charge is so small as to have little impact.
17-Apr-03	Jim Ross and Rod Aoki		Phone call	Began with Jim's questions re: ISO proposal. What is the CS billing determinant? How was that calculated? Didn't appear to Jim to be a supportable method. Jim thought the # of schedules were too small. CONG - Jim gave an example of a generator in ZP26 selling to SCE. Would the generator be assessed the CONG or would SCE be assessed on its load? I need to get back to him on this. □ Jim asked how the Market Usage billing determinant was calculated. I described what the components were. What about QFs with 100 percent on-site generation and absolutely no purchases from grid. I assumed that we would only assess the demand charge and no others. Jim's comments on ISO proposal. Getting complex and this could be a problem. CS charge is huge, but need to find a better way to recover the costs. Do something different. Set a customer charge, then move the other costs around, probably recover through an energy charge. It may be easier to mitigate once we see the #s.
17-Apr-03	Laurence Kirsch		Phone call	Call in response to Laurence's April 15th email. Discussed what number of schedules represents. Suggested that we needed to explain what # of schedules represents and what 1.6 billion MWhs of billable volumes represents. Understands how ISO costs are related to # of schedules, but not to MWhs of billable quantities. Needs explanation. Would recommend that the customer charge be done in a different way. Will send out a revised MID proposal when they get new billing determinants.

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17-Apr-03	Rod Aoki		Phone call	Discussed CAC/EPUC concerns. They had questions on # of schedules and billable quantities. Jim Ross has scheduled call with Barbara and Cathy to discuss behind the meter NCP. Rod said that process seems to be moving in right direction. Saw good things in MID and SCE proposals. Had questions about remaining issues slide. Will call me at 3:15 to discuss Jim Ross's questions
18-Apr-03	Ben Arikawa	GMC WG	e-mail message	Notice that supporting materials for ISO rate proposal are posted to confidential discussion board
18-Apr-03	Phil Leiber	Karen Shea	meeting at ISO	Discussion of 2003 Budget and CAM
21-Apr-03	Ben Arikawa	Laurence Kirsch	E-Mail Communication with attachments	Transmittal of documents requested by Dr. Kirsch during phone conversation answering his April 15th questions
21-Apr-03	Ben Arikawa	Bert Hansen	e-mail message	Asked if Bert wanted items posted
21-Apr-03	Ben Arikawa	GMC WG	e-mail message	Notice that SCE has posted on discussion board supporting materials on discussion board
21-Apr-03	Bert Hansen	Ben Arikawa	e-mail message	Transmitted preliminary rates to ISO for distribution
21-Apr-03	Bert Hansen	Ben Arikawa	e-mail message	Bert will attempt to post
21-Apr-03	ISO Market Notice	Market Participants	Market Notice	Notice that ISO intends to distribute SC-related data in GMC project
21-Apr-03	Kevin Smith		Phone call	Discussed impressions of ISO rate proposal. Kevin has a meeting with TANC (munis?) to discuss their impressions of ISO rate proposal. He will get back to me later tomorrow if he has time.
22-Apr-03	Ben Arikawa	Bert Hansen	e-mail message	Response to question about availability of billing determinants and bill impacts
22-Apr-03	Ben Arikawa	GMC WG	e-mail message	Distributed draft meeting notes to April 11 meeting and noticed April 28 meeting
22-Apr-03	Ben Arikawa	Jan Pritchard, Bert Hansen	e-mail message	Offered MID and SCE the opportunity to run through bill calculation at April 28 meeting
22-Apr-03	Bert Hansen	Ben Arikawa	e-mail message	Question about the availability of billing determinants and bill impacts
22-Apr-03	Lee Terry		Phone call	Wanted information to do bill impact analysis. Asked me questions about net uninstructed deviations. Told him to have their Settlements guy talk to our Settlements guy to see if we could give him information informally. Did not know if it would work. I could not give him the information directly.
22-Apr-03	Rod Aoki		Phone call	Follow-up call to last week's call with Jim Ross and Rod. Interzonal congestion management payment to SC that owns energy when it crosses the interzonal interface. Discussed customer charge.
22-Apr-03	Tony Lam		Phone call	Discussed agenda of next meeting. What ISO was going to do. What EOB thought of ISO proposal and if there were modifications.
23-Apr-03	Ben Arikawa	Jan Pritchard, Laurence Kirsch	E-Mail Communication	ISO presentation not ready, but will keep MID informed
23-Apr-03	Ben Arikawa	Jan Pritchard, Laurence Kirsch, Mike McGuffin, Phil Leiber	E-Mail Communication	Transmitted updated billing determinants to MID prior to general release for their use in preparing for April 28th meeting
23-Apr-03	Jan Pritchard	Ben Arikawa, Laurence Kirsch	E-Mail Communication	MID is interested, but like more information about the format of presentation
23-Apr-03	Ben Arikawa	Bert Hansen	e-mail message	Asked Bert to review April 2 conference call notes for accuracy
23-Apr-03	Bert Hansen	Ben Arikawa	e-mail message	Bert confirms that notes are accurate

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23-Apr-03	Katie Kaplan		Phone call	Response to my email message this morning. Hasn't been following the GMC much, asked that I review proposals with her. Concerns about the Customer Service charge application. Told her that we are open to different ideas and will put it on the table on Monday. Asked about consistency with other ISOs re: customer service charge. Asked that I send her the proposals documents.
24-Apr-03	Laurence Kirsch	Ben Arikawa, Jan Pritchard, Ross Hemphill, Sean Neal, Mike McGuffin	E-Mail Communication	Dr. Kirsch explains how to create the 12 month average data for NCP
24-Apr-03	Laurence Kirsch	Phil Leiber, Ben Arikawa, Jan Pritchard, Ross Hemphill, Sean Neal, Mike McGuffin	E-Mail Communication	Dr. Kirsch explains differences and adopts ISO's number of customer months
24-Apr-03	Laurence Kirsch	Phil Leiber, Ben Arikawa, Jan Pritchard, Ross Hemphill, Sean Neal, Mike McGuffin	E-Mail Communication	Dr. Kirsch looks forward to an ISO update on NCP
24-Apr-03	Mike McGuffin	Phil Leiber, Ben Arikawa, Jan Pritchard, Ross Hemphill, Sean Neal,, Laurence Kirsch	E-Mail Communication	Mr. McGuffin explains that producing 12-month rolling averages is problematic.
24-Apr-03	Phil Leiber	Laurence Kirsch, Ben Arikawa, Jan Pritchard, Ross Hemphill, Sean Neal	E-Mail Communication	Bill impacts will be updated using new MID rates
24-Apr-03	Phil Leiber	Laurence Kirsch, Ben Arikawa, Jan Pritchard, Ross Hemphill, Sean Neal, Mike McGuffin	E-Mail Communication	Mr. Leiber noted some differences in billing determinants and the need to resolve these.
24-Apr-03	Phil Leiber	Mike McGuffin, Ben Arikawa, Sean Neal, Jan Pritchard, Ross Hemphill	E-Mail Communication	Mr. Leiber asked Mike McGuffin to compile NCP based on MID's method
24-Apr-03	Phil Leiber	Mike McGuffin, Ben Arikawa, Sean Neal, Jan Pritchard, Ross Hemphill	E-Mail Communication	Mr. Leiber asks if it is necessary to wait until an acceptable NCP number is generated
24-Apr-03	Phil Leiber	Mike McGuffin, Ben Arikawa, Sean Neal, Jan Pritchard, Ross Hemphill	E-Mail Communication	Mr. Leiber points out that there is an error in the number of schedules
24-Apr-03	Laurence Kirsch	Phil Leiber, Ben Arikawa, Jan Pritchard, Ross Hemphill, Sean Neal	E-Mail Communication with attachment	Dr. Kirsch transmits updated MID proposal and presentation for April 28th meeting
24-Apr-03	Laurence Kirsch	Ben Arikawa, Phil Leiber, Jan Pritchard, Ross Hemphill, Sean Neal	E-Mail Communication with attachments	Transmittal of updated MID rates using data from 04/23/2003.
24-Apr-03	Ben Arikawa	GMC WG	e-mail message	Notice that SCE has posted its rates on discussion board
24-Apr-03	Phil Leiber	Karen Shea;Edmister, Todd; Lam, Tony; "Iklé, Judith C."; GMC WG; Jercich, Scott	e-mail message	Response to Karen's e-mailed questions about possible FTR and ETC charges

Attachment 2 - Stakeholder Process Contacts

Date	Person(s)	Recipient	Type	Description
24-Apr-03	Laurence Kirsch		Phone call	Wanted disaggregated data on market usage. It was sent yesterday, but Laurence missed it. Discussed whether MID wanted to give sample transaction. Laurence didn't think it was necessary, but would get with Jan.
25-Apr-03	Ben Arikawa	Ross Hemphill and Jan Pritchard	E-Mail Communication	Mr. Arikawa notifies MID attorney review is needed prior to release of data to MID
25-Apr-03	Phil Leiber	Mike McGuffin, Ben Arikawa, Sean Neal, Jan Pritchard, Ross Hemphill	E-Mail Communication with attachment	Mr. Leiber transmits updated MID bill impacts using updated rates
25-Apr-03	Ben Arikawa	Ross Hemphill and Jan Pritchard	E-Mail Communication with attachment	Mr. Arikawa transmits load and deviation data to MID
25-Apr-03	Ben Arikawa	Alessandri, Patrick; Aoki , Rod; Bliven, Ray; Bray, Peter; Brommer, Mike; Call, Harrison; Cohen, David; Cuillier, James; Franklin, Brett; Grammer, Elisa; Griess, Bryan; Hansen, Bert; Hemphill, Ross; Kehrein, Carolyn; Key, Jennifer; Kirsch, Laurence; Kissel, Peter; Lam, Tony; Mi, Jingchao; Minick, Mark; Neal, Sean; Olsson, Ray; Postar, Mike; Pritchard, Jan; Ross, James A; Ryan, Mike; Schoenbeck, Don; Shockey, Neil; Smith, Kevin; Still, Jim; Takehara, James; Terry, Lee; Werner, Michael; Yakin, Dale	e-mail message	Agenda with call in number for confidential portion of April 28 meeting
25-Apr-03	Ben Arikawa	GMC WG	e-mail message	Posting of GMC meeting documents
25-Apr-03	Ben Arikawa	GMC WG	e-mail message	Posting of bill impact analyses to discussion board.
25-Apr-03	Karen Shea	Phil Leiber;Edmister, Todd; Lam, Tony; "Iklé, Judith C."; GMC WG; Jercich, Scott	e-mail message	Questions on proposed customer service charge
25-Apr-03	Dale Yakin		Phone call	Responded to his email concerning billing determinant data. Discussed what would be presented at meeting on Monday. What about Customer Service charge? billable quantities where is that? Suggested that we are open to looking at different methods for recovery of CS.
27-Apr-03	Karen Shea	Phil Leiber;Edmister, Todd; Lam, Tony; "Iklé, Judith C."; Arikawa, Ben	e-mail message	Comments on trend of deviations and their potential effect on ISO rate proposal
28-Apr-03	Ben Arikawa	Laurence Kirsch	E-Mail Communication with attachment	Mr. Arikawa transmits bill impact spreadsheets to Dr. Kirsch
28-Apr-03	Ben Arikawa	GMC WG	e-mail message	Distributed updated cost component information presentation and backup documentation

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28-Apr-03	Phil Leiber	Karen Shea;Edmister, Todd; Lam, Tony; "Iklé, Judith C."; GMC WG	e-mail message	Response to Karen's e-mailed questions from April 25
28-Apr-03	GMC WG		Stakeholder meeting at ISO	1.Introductions/roll call 2.SCE proposal update 3.MID proposal update 4.ISO proposal update a.Cost components b.Custome Service cost recovery c.Example rate calculation 5.Discussion of timeline
29-Apr-03	Laurence Kirsch	Mike McGuffin, Ross Hemphill, Blagoy Borissov, Ben Arikawa	E-Mail Communication	Dr. Kirsch describes data to be burned to CD and Fed-Ex'ed to Blagoy Borissov
30-Apr-03	Ben Arikawa	Laurence Kirsch and Ross Hemphill	E-Mail Communication	Mr. Arikawa notifies Drs. Kirsch and Hemphill that data distribution will be delayed
30-Apr-03	Lee Terry	Ben Arikawa	e-mail message	Questions about bill impact spreadsheet
30-Apr-03	Lee Terry	Ben Arikawa	e-mail message	Questions about GMC analysis tool
30-Apr-03	Dale Yakin		Phone call	Asked about main drivers of bill impacts - demand vs. energy and #of schedules? Is ISO going to do more on ETCs? Only because CPUC is pushing. Dale did not know if PG&E would agree with CPUC. Is PG&E NCP the same as CP? Probably. (have to check for Dale) Question - if SCE was overgenerating and PG&E under, in order to accomodate SCE, how would this affect CRS bill? My answer, should not, because CRS is load based, generation doesn't affect it. Some discussion of customer service cost recovery.
30-Apr-03	Jan Pritchard		Phone call	Viewed progress as good. Still has problem with Customer Service as it is a fixed cost.
30-Apr-03	Laurence Kirsch		Phone call	Asked about possible errors in bill impact spreadsheets. Also asked about UE data.
30-Apr-03	Shannon Black		Phone call	Asked about NDA. E-mailed copy to him later.
30-Apr-03	Tony Lam		Phone call	Discussed customer service cost recovery. What was EOB's view? Was it the same as the CPUC's? Could EOB get together with the CPUC to work on a proposal for recovery?
01-May-03	Karen Shea	Ben Arikawa Edmister, Todd; Leiber, Phil; Kissel, Peter; Lam, Tony; Shea, Karen	e-mail message	Discussion of customer charge
01-May-03	David Cohen		Phone call	Talked about bounced email message that he sent to Phil. Said that the ISO's proposed GMC is about as complicated as it can get. Asked if there is a way to accomodate MID's proposal. Also asked if we could bifurcate the process so that we do only what needs to get done for the Budget by June and work on the rest through September

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01-May-03	Lee Terry		Phone call	Response to questions e-mailed yesterday. Answer (1) in market worksheet, ID 28 shows up three times, once for AS, IE and net UE. (2) Billing determinant for Market Usage was updated to 45 million MWhs from 38 million. Asked him about CDWR position on Customer Service. They will have a meeting on Tuesday to discuss.
02-May-03	Ben Arikawa	Laurence Kirsch, Ross Hemphill, Jan Pritchard, Phil Leiber, Stephen Morrison, Mike McGuffin and Debi Le Vine	E-Mail Communication	Mr. Arikawa notifies Drs. Kirsch and Hemphill that data will be sent out this day.
02-May-03	Mike McGuffin	Laurence Kirsch, Ross Hemphill, Jan Pritchard, Phil Leiber, Stephen Morrison, Ben Arikawa and Debi Le Vine	E-Mail Communication	Mr. McGuffin acknowledges that there are problems with the data that should be corrected.
02-May-03	Ben Arikawa	GMC WG	e-mail message	Scheduling of meetings and conference calls in May
02-May-03	Ben Arikawa	Karen Shea; GMC WG	e-mail message	Response to May 1 comments from Karen Shea
02-May-03	Phil Leiber	David Cohen, Mike Postar, Stephen Morrison, Ben Arikawa	e-mail message	Responded to David's request for unmasking IDs. Response was that the ISO needed confirmation from parties being unmasked that David had authorization to see data
02-May-03	Rod Aoki		Phone call	Discussed customer service charge. Whether Midway would be able to get more recent data, since the data used only has two months of Midway activity. Passed request onto Stephen.
05-May-03	Ben Arikawa	GMC WG	e-mail message	Distributed GMC briefing notes including listing of available confidential information
05-May-03	David Bonaly	Ben Arikawa, Mike Werner, Lee Terry	e-mail message	Raises CDWR issue with the CRS definition
05-May-03	Tony Lam	Ben Arikawa, Jeff Slation, Ray Olsson	e-mail message	Request for deviation data given to MID
06-May-03	Laurence Kirsch	Ben Arikawa, Mike McGuffin, Phil Leiber, Ross Hemphill, Jan Pritchard, Sean Neal	E-Mail Communication	Dr. Kirsch points to unexpectedly large bill impacts to a single masked SC ID.
06-May-03	Laurence Kirsch		Phone call	Asked what type of activity was #231 in. I told him I would get back to him about it.
07-May-03	GMC WG		Conference call	1.Introductions/roll call 2.Review of options submitted to ISO 3.Discussion of options
07-May-03	Ben Arikawa	Lee Terry	e-mail message	Resent cost components presentation and accompanying
07-May-03	Laurence Kirsch		Phone call	Told him that #231 was a trader. Gave a recounting of the conference this afternoon. He will have another presentation for Monday.
08-May-03	Ben Arikawa	GMC WG	e-mail message	Agenda for May 12 meeting and MIF presentation
08-May-03	Ben Arikawa		MIF presentation	Discussed 2004 GMC Rate Structure Project and progress so far and FERC Opinion 463
08-May-03	Bert Hansen		Phone call	Discussed analysis of SCE DDES charge impact. Will send to him to distribute to participants. Asked questions about analogy between muni behind the meter generation and SCE generation connected at distribution level.

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08-May-03	Lee Terry		Phone call	Discussed what was in the spreadsheets (CAM, direct labor ratios). Asked about CRS and using 12 CP instead of 12 NCP. Whether than analysis was done. Discussed progress of process thus far.
09-May-03	Ben Arikawa	Bert Hansen	e-mail message	Transmitted bill impact spreadsheets and informed Bert that SCE is identifiable from bill impacts. Informed Bert that it is up to SCE if it is willing to release this information and waive confidentiality
09-May-03	Ben Arikawa	David Cohen	e-mail message	Transmitted MD02 ETC spreadsheet with modifications requested by David
09-May-03	Ben Arikawa	GMC WG	e-mail message	Distributed documents for May 12 meeting
09-May-03	Ben Arikawa	GMC WG	e-mail message	Posting of 12 CP 12 NCP comparison spreadsheet
12-May-03	Ben Arikawa	GMC WG	e-mail message	Distributed additional documents for public portion of meeting
12-May-03	GMC WG		Stakeholder meeting at ISO	Public Session 1.Introductions/roll call 2.Stability of billing dete minants 3.SCE proposal update 4.MID proposal update 5.ISO proposal update a.Example bill calculation b.Impact of 12 CP vs.12 NCP on rates c.Impact of DDES exemption on rates d.Customer Service cost recovery discussion 6.Discussion of Order in ER01-313-000 7.Discussion of timeline Confidential Session 1.Discussion of billing impacts a.SCE i.Impact of DDES b.MID c.ISO i.Impact of DDES ii.Impact of 12 CP vs.12 NCP
14-May-03	Ben Arikawa	Lee Terry	e-mail message	Responding to questions about bill impacts
14-May-03	Laurence Kirsch		Phone call	Wanted to know about schedules, physical vs financial. Want to talk to someone here directly about that.
14-May-03	Shannon Black		Phone call	Had a series of questions that I couldn't answer specifically. He said that he would post his questions. He sent them by e-mail and cc'ed Kyle. Kyle responded by phone. questions were posted on May 19th.
15-May-03	Ben Arikawa	GMC WG	e-mail message	Distributed GMC briefing notes
16-May-03	Ben Arikawa	Bert Hansen	e-mail message	Responded to Bert's e-mail message by distributing and asking for a response internally.
16-May-03	Bert Hansen	Ben Arikawa	e-mail message	Asked for definition of net control area load. Informed ISO that SCE would want equal treatment for any netting of distribution connected load.
19-May-03	Ben Arikawa	David Cohen	e-mail message	Transmitted in three parts CAMs for each proposal, bill impacts spreadsheets

Date	Person(s)	Recipient	Type	Description
19-May-03	David Cohen		Phone call	Discussed meeting dates and times. Dave is not available after June 4th until June 24th because he has to file on the FERC TAC cases. Asked if Board could vote on functionalization in June, but move out rate function approval until July. I told him that he or his clients could make the case for that before the Board. Dave was concerned that the Board wouldn't listen, but I say they should try for something might happen. Wants to go over CAM line by line. Asked if we could delay filing until Dec 1 and ask for 30 day approval. Might be able to get his clients to buy off on that. Asked if we or anyone had done a comparison of the MID and ISO proposals. (No.) Asked if we could get around the stale data problem. (fresh data is coming)
19-May-03	Jan Pritchard		Phone call	Discussed need to have MID make its issues known before the Board on June 6th. It would be better to have them informed prior to the June 26th meeting. Jan will ask Laurence as to his availability.
20-May-03	Ben Arikawa	GMC WG	e-mail message	Scheduling of late May meeting and proposed topics
20-May-03	Jan Pritchard		Phone call	Discussed what MID might present at the June 6th Board meeting.
21-May-03	Ben Arikawa	GMC WG	e-mail message	Distributed Dr. Kirsch's memo on why tiers are reasonable
21-May-03	Rod Aoki		Phone call	Discussed what we might be doing on standby load and the topics for May 28th meeting.
23-May-03	Karen Shea	Phil Leiber;Edmister, Todd; Orbeta, Robert; Yakin, Dale; Hansen, Bert; Hitson, Brian; Shea, Karen; Lam, Tony; Arikawa, Ben; "Iklé, Judith C."	e-mail message	CPUC provides its mapping of SCs to customer classes
23-May-03	Phil Auclair		Phone call	Asked for a description of how rates work. Wanted to know if he could find data to reconstruct bill impacts for Mirant. Told him that if Mirant signed the CA and NDC, we could give him all the data and show bill impacts. He didn't need to do it himself. Also, impressed on him the importance of signing, since all data would be available.
27-May-03	Lee Terry	Ben Arikawa	e-mail message	Issues with billing determinant data and password to confidential discussion site.
27-May-03	Lee Terry		Phone call	Discussed sources of billing determinant data used by SCE. Told him that the ISO would be sending out spreadsheet containing the data later today. He also had an issue with the password to the confidential discussion site.
27-May-03	Rod Aoki		Phone call	Asked if CAC could have an opportunity to speak at the June 6th Board meeting. Talked about standby tariff and munis.
28-May-03	Ben Arikawa	GMC WG	e-mail message	Distribution of documents for today's meeting
28-May-03	Karen Shea	Phil Leiber, Ben Arikawa	e-mail message	Last message in an exchange between Karen Shea and Phil Leiber on questions about the CRS billing determinant
28-May-03	Karen Shea	Phil Leiber; Edmister, Todd; Orbeta, Robert; Yakin, Dale; Hansen, Bert; Hitson, Brian; Lam, Tony; Arikawa, Ben; "Iklé, Judith C."; Firooz, Sharon	e-mail message	CPUC provides a correction to its mapping of SCs to customer classes and asks a question about DDES

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28-May-03	Cathy Yap		Phone call	Left message about her and Barbara's conference call with Jim Ross and Rod Aoki. Jim said that SCE had mixed standby and supplemental power together in its effective demand factor.
28-May-03	Kathleen Wright		Phone call	Jerry Green passed message from me to her. 574-0346
28-May-03	Lee Terry		Phone call	Left message re: more disaggregation of CRS. mitigation for DWR. 574-0664
28-May-03	Rod Aoki		Phone call	Rod relayed message from Jim. Jim was having trouble being heard on conference call. Jim thought that there was some problems with the Edison effective demand factors. He would send something out soon to Cathy, Barbara and me. Jim wants to talk to Katie about why QFs and munis are different.
28-May-03	Rod Aoki		Phone call	Asked for a copy of GMC Analysis tool for Jim to use. Discussed that new tool had everything that Jim would need to do bill impact analysis over all proposals.
28-May-03	Sharon Firooz		Phone call	Left message re:what is going on in GMC. She is taking over from Ed Lucero.
28-May-03	GMC WG		Stakeholder meeting at ISO	1.Introductions/roll call 2.SCE proposal update 3.MID proposal update 4.ISO proposal update a.Initial review of data and calculations b.Implementation of Settlements,Metering and Client Relations cost recovery c.Application of CRS charge to Standby Tariff NCP 5.Bill impact analysis 6.Initial discussion of scheduling activities 7.Initial review of Appendix B issues 8.Discussion of timeline
29-May-03	Ben Arikawa	David Cohen	e-mail message	Transmitted MID revised proposal and updated bill impacts spreadsheets
29-May-03	Rod Aoki	James A. Ross, Ben Arikawa	e-mail message	Transmitted PG&E data that Jim obtained
30-May-03	Rod Aoki		Phone call	Talked about setting up a conference call with Cathy and Barbara for sometime early next week. Gave me Monday or Tuesday mornings as good times.
30-May-03	Sharon Firooz		Phone call	Discussed status of GMC project. Sharon wanted to know what was going on as she was taking over for Ed Lucero. Talked about each proposal. She wanted something written on each one. She wanted to know the bill impact on SDG&E. Sent her all the proposals, contact list for her to see.
02-Jun-03	Rod Aoki, Jim Ross, Barbara Barkovich, Cathy Yap, Ben Arikawa		conference call	Discussion of PG&E QF data and diversification factor
02-Jun-03	Ben Arikawa	David Cohen	e-mail message	Transmitted frequency distribution of bill impacts. David wanted to use that to see if he could develop a customer charge
02-Jun-03	Ben Arikawa	GMC WG	e-mail message	Distributed proposed agenda for June 4 meeting
02-Jun-03	Rod Aoki	Jim Ross, Barbara Barkovich, Cathy Yap, Ben Arikawa	e-mail message	Additional data obtained by Jim Ross

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02-Jun-03	David Cohen		Phone call	Discussed addition of item to June 4th agenda. Dave wanted to see a copy of the applications flow chart that Mike McGuffin showed him on April 11. He also wanted to have observers sitting in on the interviews that Cathy and Barbara would have with directors and managers. He said that he's asked his attorneys to send a "protest" to the ISO on this and he would have them take it up with the judge if we turned him down.
02-Jun-03	Rod Aoki, Jim Ross, Barbara Barkovich, Cathy Yap		Phone call	Follow-up discussion with Jim and Rod concerning ISO CRS demand application to standby load. Much of the discussion was about clarification. Jim had load data for 1998 and 1999 that he used in the 2001 GMC proceeding.
04-Jun-03	Ben Arikawa	GMC WG	e-mail message	Scheduling of conference calls and meetings for June
04-Jun-03	GMC WG		Stakeholder meeting at ISO	Agenda: 1. Introductions/roll call 2. Discussion of June 6 Board Presentation 3. Initial review of Appendix B issues 4. Initial review of billing determinant stability 5. SCE proposal update 6. MID proposal update a. Development of tiered rates b. New portions of proposal 7. ISO proposal update a. Behind the meter load NCP b. Discussion of scheduling activities c. Discussion of functional association of Settlements, Metering and Client Relations costs d. Discussion of cost assignment method (if time permits) Agenda - confidential session 1. Bill impact analysis 2. Discussion of cost assignment method (if time permits)
05-Jun-03	Katie Kaplan		Phone call	Discussed ISO proposal, specifically the scheduling charge. What effect does the must offer requirement have? Will generators get charged the scheduling charge for must offer and for RUC? Does any other ISO have a charge on schedules? (ISO-NE does) When through simple examples. Cost could be cumulative and fairly high for a unit that had several schedules per hour.
06-Jun-03	Ben Arikawa	GMC WG	e-mail message	Notice of posting of revised bill impact spreadsheets
06-Jun-03	Kathleen Wright		Phone call	Discussed if CERS was interested in participating. Kathleen brought up the scheduling charge. CERS not in the business anymore, it's all a passthrough for them. Send in papers and charges so that she could pass them onto Zora and Byron.
06-Jun-03	Phil Leiber, Ben Arikawa	ISO Board	presentation	Initial presentation to ISO Board describing GMC history and process

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09-Jun-03	Bert Hansen		Phone call	I just finished talking to Bert Hansen of SCE. He was interested in (1) the results of the Board meeting and if the schedule had changed as a result of that and (2) if the scatterplots of the ISO proposal contained the association of Settlements, Metering and Billing to other billing determinants. The discussion on the former was that we still hope to keep to the schedule and we still expect to have MID and SCE make presentations to the Board on the 26th. Finally, I asked Bert if SCE were using net uninstructed deviations or just plain deviations because this question arose from our Swidler friends who are writing reply comments on the 2001 GMC rehearing requests. It turns out that we had been using the wrong billing determinant for SCE's RMOS charge (I think that Bert originally used the wrong number and we just carried it through). I've changed the BD in the bill impacts spreadsheet and Edison's small net reduction is now a $2 million increase under their own proposal. I'll send it out to Bert and the GMC WG after I've had a chance to go over the numbers to look for errors.
09-Jun-03	Bert Hansen		Phone call	Bert called to ask if the CRS BD would change now that we were using metered demand rather than metered demand plus an adder. The answer was no, the numbers already reflected metered demand and it was the adder the ISO was looking for. I pointed out to Bert that the use of total deviations would result in higher charges to SCE. Bert said that net deviations was what he wanted.
10-Jun-03	Ben Arikawa	GMC WG	e-mail message	Distributed proposed agenda for June 16 conference call
10-Jun-03	Kevin Smith		Phone call	Wanted to know if ISO documents had been updated since April. Needed them to prepare for a conference call with his clients on GMC to discuss MID and ISO proposals. Directed him to rates summary from June 4th meeting and sent him links to ISO budget documents.
10-Jun-03	Philippe Auclair		Phone call	GMC issues. What does Kirsch mean? ISO Board happenings. How do deviations apply.
16-Jun-03	GMC WG		Conference call	1.Introductions/roll call 2.Updates a.SCE proposal b.MID proposal c.ISO proposal 3.Discussion of SDG&E issues 4.June 6 Board discussion 5.June 26 Board presentations a.What to expect b.Participant opinions on proposals and process 6.Bill impact analysis update 7.Discussion of timeline
17-Jun-03	Ben Arikawa	David Cohen	e-mail message	Transmitted reduced size bill impacts spreadsheet on his request

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17-Jun-03	Bert Hansen		Phone call	Discussed what new numbers for billing determinants SCE needs. Discussed calculations for determining both the energy and NCP of Mohave exports. Bert used 5.4 million MWhs as SCE's 56 percent share of Mohave energy. Nevada Power (10%) and SRP (24%) would have 3.3 million MWhs of energy (5.4/.56*.34) Similarily, the NCP would be 1580 MWs (total Mohave) * .34 * 12 = 6450 MW-months Also discussed ways that SCE could avoid charges on Mohave exports. Bert pointed out that the new billing determinant for NCP on CAS would be reduced by the generation connected at distribution level (5 - 7 percent).
17-Jun-03	David Cohen		Phone call	Discussed ISO system applications flow diagram. Stephen Morrison is working on getting something out in 3 weeks. (need to ask Stephen if it will be out prior to June 30th meeting). Asked David if he is still working on tiered SMCR charge. He is not. He asked me if there is an opportunity to compromise with MID on its proposal. Figures SCE will go to the wayside if they get their DDES charge. David was concerned about timing of the July Finance Committee meeting.
18-Jun-03	Sharon Firooz		Phone call	Discussed bill impacts spreadsheet, location of billing determinants for each specific ID. She requested some clarification of what is a schedule (really, why are the import schedules twice the export schedules). The SDG&E white paper on why SWPL should not be assess GMC will be out soon. We (ISO and SDG&E) might have a conference call after that comes out. Depends on what the principals want.
18-Jun-03	Tony Lam		Phone call	Discussed conference call on 16th. Tony was not on the line.
19-Jun-03	Ben Arikawa	GMC WG	e-mail message	Distribution of proposed agenda for June 30 meeting
19-Jun-03	Ben Arikawa		MIF presentation	Discussed GMC rate design process and timeline for Board review
19-Jun-03	David Cohen		Phone call	Discussed times for Finance Committee meeting. He brought up SB 138? about transmission for renewable generation.
19-Jun-03	Jan Pritchard		Phone call	Discussing schedule for Finance Committee meeting in July. Jan wants to see white paper as ISO proposal has been changing.
19-Jun-03	Laurence Kirsch		Phone call	Discussed data on energy trades. How the HA market functions. Discussed dates for Finance Committee meeting
20-Jun-03	Ben Arikawa	GMC WG	e-mail message	Posting of Board documents on GMC
20-Jun-03	Lee Terry	Ben Arikawa	e-mail message	Found error in spreasheet
20-Jun-03	Stephen Morrison	David Cohen, GMC WG	e-mail message	Explained to David why the ISO could not distribute a copy of its system applications flow chart. ISO would look into developing one that could be distributed under the NDC.
26-Jun-03	Debi Le Vine	ISO Board	presentation	Presentation to ISO Board describing GMC history and process
25-Jun-03	Ben Arikawa	GMC WG	e-mail message	Documents for June 30 meeting
27-Jun-03	Ben Arikawa	GMC WG	e-mail message	Distributed GMC briefing notes

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27-Jun-03	David Cohen		Phone call	Discusses what is in the Billing determinants data. Specifically, is SMUD removed. SMUD load is removed, but transactions still occur. Have I heard from Bert re: the 75 percent discount rather than the 90 percent discount. Will the ISO be commenting on MID's proposal. ISO has been very quiet. Is SDG&E going to issue a white paper on SWPL?
30-Jun-03	Ben Arikawa	GMC WG	e-mail message	Distribution of B&Y presentation for GMC meeting
30-Jun-03	Ben Arikawa	GMC WG	e-mail message	Rescheduling of July 8 meeting to July 7 with proposed topic
30-Jun-03	GMC WG		Stakeholder meeting at ISO	Public Session Conference Call-in 1.Introductions/roll call 2.Updates a.SCE proposal b.MID proposal c.ISO proposal 3.SDG&E issues 4.ISO topics a.Discussion of use of non-coincident peak b.Discussion of functional association of cha ge types 5.Discussion of timeline 6.Data a.Billing determinant stability b.Data verification Confidential Session 7.Discussion of cost allocation method 8.Bill impact analysis update
01-Jul-03	Dale Yakin		Phone call	Recounted June 30th meeting (he did not attend). Was he going to attend the July 17th Finance Committee meeting?
01-Jul-03	David Cohen		Phone call	Asked about time of July 7th conference call and who would be on the call for ISO (B&Y?) Tony and Kevin would be present at Finance Committee meeting for CMUA. He was troubled over the lack of preparation for the June 30th meeting nothing was locked down. Concerns 1. Concerned that Board % assignments would be locked in through filing in Nov 2. $93 million was too high for CRS 3. SCE could have settled months ago, if they were willing to talk 4. SCE couldn't give a yes or no on the 75% discount on GRS 5. What about the CPUC issues (ETCs) 6. White paper What was missing in the white paper and the discussions was the impact of the rate design on MSSs. He wanted to be certain that MSSs were treated consistently.

Attachment 2 - Stakeholder Process Contacts

Date	Person(s)	Recipient	Type	Description
01-Jul-03	Jan Pritchard		Phone call	Asked if there would be a conference call on the 8th. He saw no need for one. Jan would be at the Finance Committee meeting with Roger Van Hoy and possibly Mike Kreamer. He was looking forward to a settlement conference after the filing.
01-Jul-03	Lee Terry		Phone call	CDWR would have a 10 minute presentation. Up to 4 people from CDWR would attend. Discussed topics for July 7th conference call.
01-Jul-03	Phil Auclair		Phone call	Discussed GMC questions
01-Jul-03	Rod Aoki		Phone call	CAC would be attending the July 17th Finance Committee meeting and would have a short statement. Asked if I had talked to Stephen on the exemption issue to the gross meter reporting requirement.
01-Jul-03	Tony Lam		Phone call	Tony and Jeff Slaton would be attending the Finance Committee meeting.
01-Jul-03	Tony Lam		Phone call	Asked about the status of the SCE proposal and how COTP would be treated.
02-Jul-03	Carrie Downing		Phone call	Asked about the July 17th meeting and directions to the ISO. Would be attending for IID.
02-Jul-03	Sharon Firooz		Phone call	Asked about the FERC order and the requests for rehearing and clarification. What was in the decision about behind the meter load? On July 17th, there would be 3 people from SDG&E. Asked about the forum for dealing with SCE's issues.
03-Jul-03	Lee Terry		Phone call	What were the topics for Monday's conference call. Big issues for CDWR $47 million in SMCR, functional association of charge types and $93 million in CRS.
07-Jul-03	NDC signatories		Conference call	Discussion of ISO cost assignment methodology
07-Jul-03	David Cohen		Phone call	Asked for e-mail addresses of attendees. Asked who would be on the call for the ISO. His big ticket items were: logic of assignment of startup with new functionalization. 98 bonds should be thought of as responsibility of participants in 1998. When over white paper edits.
08-Jul-03	Ben Arikawa	David Cohen, Lee Terry	e-mail message	Sent updated bill impacts spreadsheet
08-Jul-03	David Cohen		Phone call	Went over bill impacts. He finally realized who #11 was.
10-Jul-03	Gerry Stillwagon		Phone call	Wanted to know how ISO GRS would be applied. If it included behind the meter load, whether COTP flows got charged.
10-Jul-03	Lee Terry, Kevin Smith, Jan Pritchard, Mike Ryan		Phone call	Discussed CPUC request for bill impacts aggregated by customer classes. (different calls during the day on same subject)
11-Jul-03	Ben Arikawa	Kehrein, Carolyn; Auclair, Philippe; Lam, Tony; Bray, Peter; Shea, Karen; Kissel, Peter; Bonaly, David; Sandino, David; Werner, Michael; Terry, Lee; Walz, Edna	e-mail message	Transmitted updated spreadsheet summarizing the bill impacts under different proposals. Includes the 12 CP proposed by CDWR
14-Jul-03	Dale Yakin		Phone call	Asked about SCE's net load proposal and the NCP. PG&E had some support for the ISO proposal, but didn't know if it would provide comments in response to Phil Leiber's e-mail request. Wondered why MID was working so hard on its proposal. Mentioned that billing determinants are complicated.
14-Jul-03	Lee Terry		Phone call	Asked about the Finance Committee agenda and some details about the market usage and CRS charges.

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15-Jul-03	David Bonaly		Phone call	CDWR wanted to have equal status as the other presentors.
15-Jul-03	Phil Auclair		Phone call	Discussed GMC issues
15-Jul-03	Rod Aoki		Phone call	Discussed CAC's request for Midway Sunset data. He would raise the issue of temporary exemptions from gross metering requirement and mitigation of forward scheduling costs. Brought up some issues regarding past dealings with the ISO. Mentioned the rehearing decision in TAC.
16-Jul-03	Ben Arikawa		MIF presentation	Discussed changes in timeline and what Board will hear
16-Jul-03	Bert Hansen		Phone call	What's up tomorrow?
16-Jul-03	Jan Pritchard		Phone call	No notes
16-Jul-03	Sharon Firooz		Phone call	Asked about the board presentations and format of them
17-Jul-03	ISO, SCE, MID	ISO Finance Committee	presentations	Rate proposals presented
18-Jul-03	Bert Hansen		Phone call	No notes
18-Jul-03	Laurence Kirsch		Phone call	What does Gage want for next week? Had issues with scheduling charge, in particular the inter-SC trade charge.
21-Jul-03	Ben Arikawa	GMC WG	e-mail message	Distributed GMC briefing notes
21-Jul-03	Jan Pritchard		Phone call	Asked about who Laurence would be presenting to, the Board of the Finance Committee. Will ISO make a presentation and what are the next steps
21-Jul-03	Kevin Smith		Phone call	Does Gage want a response from CMUA?
21-Jul-03	Lee Terry		Phone call	Wanted to know about making a presentation to the full Board. Gave him Kim Hubner's number and told him to call her directly to work out logistics. Asked about the CPUC's classes. He had talked to Karen Shea about this. He wanted to know how it was done.
22-Jul-03	Jan Pritchard		Phone call	Asked about the presentations at the Finance Committee meeting.
22-Jul-03	Rod Aoki		Phone call	Some brief questions about the Board meeting.
22-Jul-03	Susan Schneider		Phone call	Questions about the Finance Committee meeting and clarification of SCE proposal
23-Jul-03	Sharon Firooz		Phone call	Asked about SCE net proposal. What do munis pay now. Only MID/TID are not metered, but they still pay gross. What do they pay under new proposal? Wanted to know where the inconsistency was.
24-Jul-03	ISO, SCE, MID	ISO Finance Committee	Presentations	Presentations and discussion of rate proposals
24-Jul-03	ISO Board			Discussion and vote on rate proposals
29-Jul-03	GMC WG		Conference call	Discussion of SCE proposed grid demand
31-Jul-03	Bert Hansen	Ben Arikawa	e-mail message	SCE written proposal on grid demand and supporting documentation
31-Jul-03	Jan Pritchard		Phone call	Asked when the ISO would have its information request out.
01-Aug-03	GMC WG		Conference call	Discussion of SCE proposed grid demand
01-Aug-03	Ben Arikawa	GMC WG	e-mail message	Distributes ISO information request in response to Board request for further analysis
01-Aug-03	Ben Arikawa	David Cohen	e-mail message	Correction to aggregated billing determinants spreadsheet in response to Mr. Cohen's pointing out of an error.
01-Aug-03	Karen Shea	Ben Arikawa, Karen Shea, Todd Edmister, Stephen Morrison, Phil Leiber	e-mail message	Questions about TID, MID, WAPA and MSSs and what they pay in GMC
01-Aug-03	Dale Yakin		Phone call	SCE net proposal difficult for PG&E to implement. Will call Bert to discuss their issues.

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01-Aug-03	David Cohen		Phone call	Talked about CMUA issues: Cost reductions biggest issue. Pointed out some incorrect numbers in billing determinants spreadsheet. Addressed some questions raised during conference call.
04-Aug-03	Ben Arikawa	Dale Yakin	e-mail message	Last message in an exchange between Dale Yakin and Ben Arikawa on deviation penalties
04-Aug-03	Jan Pritchard	Ben Arikawa, GMC WG, Mike Kreamer, Roger Van Hoy	e-mail message	Comment on and correction to July 29, 2003 conference call notes
04-Aug-03	Rod Aoki	Ben Arikawa, James A. Ross	e-mail message	Request for updated Midway Sunset data used in bill impact analysis
04-Aug-03	Jan Pritchard		Phone call	Discussed edits to conference call notes, ISO information request and conference call on Wednesday.
04-Aug-03	Kevin Smith		Phone call	Kevin was a bit perplexed by everything going on. Wanted to know ISO's view on MID's issues. Discussed SCE's proposal and what parts were net and gross.
04-Aug-03	Mike Brommer		Phone call	Asked about data request. TID would report using EIA Form 412 data.
04-Aug-03	Rod Aoki		Phone call	Discussed Friday conference call. Rod and Jim Ross had been in hearings most of last week and on Monday. Asked for Midway Sunset data. Will be sent in the next day.
04-Aug-03	Sharon Firooz		Phone call	Asked about the ISO information request. It was too broad and went to units that SDG&E no longer controlled. Told her to only respond for SDG&E controlled or scheduled units. Asked about auxiliary load at power plants and how that should be treated. T
05-Aug-03	Ben Arikawa	Rod Aoki, James A. Ross, Stephen Morrison, Debi Le Vine, Phil Leiber	e-mail message	Data requested by CAC for Midway Sunset
05-Aug-03	Bert Hansen	Ben Arikawa, GMC WG	e-mail message	Questions relevance of some parts of the ISO information request
05-Aug-03	Mike Ryan		Phone call	Asked who would report WAPA resources, WAPA or PG&E. Concerned that either it would be overlooked or double-counted.
05-Aug-03	Phil Auclair		Phone call	Auxiliary load charges. When is the conference call for tomorrow.
06-Aug-03	GMC WG		Conference call	Discussion of SCE proposed grid demand
06-Aug-03	Ben Arikawa	Kevin Smith	e-mail message	Request for assistance from CMUA in gathering information needed to respond to ISO Board request for more information concerning impact of SCE grid demand proposal and diversified demand factors
06-Aug-03	Ben Arikawa	Karen Shea, GMC WG	e-mail message	Response to questions about TID, MID, WAPA and MSSs and what they pay in GMC
06-Aug-03	Ben Arikawa	Dale Yakin	e-mail message	Response to Mr. Yakin's question about the definition of "full service load factor"
06-Aug-03	Mike Brommer	Ben Arikawa	e-mail message	TID response to ISO information request
06-Aug-03	Bert Hansen		Phone call	Asked if SCE is interested in conference call with PG&E and SDG&E to talk about gathering data. Will call Dale Yakin at PG&E and Sharon Firooz to see if they are willing. Bert is available after 10 and after 2 tomorrow.
06-Aug-03	Kevin Smith		Phone call	How can you help CMUA get stuff back to ISO on this generation at distribution level.
06-Aug-03	Kevin Smith		Phone call	MSSs get netted? Dilemma. Getting data is not the easiest thing? Why wasn't this a market notice? Having a problem figuring it out for their members.
06-Aug-03	Kevin Smith		Phone call	Is there a conference call today? Western control area discussion.

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06-Aug-03	Phil Auclair		Phone call	Discussed conference call today.
06-Aug-03	Sharon Firooz		Phone call	Conference call with Bert and Dale tomorrow 2-4 pm.
07-Aug-03	Rod Aoki and Jim Ross		Phone call	Discussed diversity factors. Where we were back in May. Asked for a conference call with B&Y on it. Called Cathy to arrange it for next Monday.
08-Aug-03	Bert Hansen	Ben Arikawa, Neil Shockey	e-mail message	Request that certain portions of SCE response to ISO information request be kept confidential
08-Aug-03	Bert Hansen	Ben Arikawa	e-mail message	SCE response to ISO information request
08-Aug-03	Charles Guss	Ben Arikawa	e-mail message	Anaheim's response to ISO information request
08-Aug-03	Jan Pritchard	Ben Arikawa, Laurence Kirsch, Sean Neal, Mike Kreamer, Roger Van Hoy	e-mail message	MID response to ISO information request of August 1, 2003
08-Aug-03	Robert Delgado	Ben Arikawa	e-mail message	Riverside response to ISO information request
08-Aug-03	Sharon Firooz	Ben Arikawa	e-mail message	SDG&E response to ISO information request
08-Aug-03	Bert Hansen		Phone call	Discussed confidential concerns about "grid demand" numbers. Part of SCE's response will be confidential. I agree, subject to check with Morrison.
08-Aug-03	Dale Yakin		Phone call	PG&E is working diligently on information request but will not have it until Tuesday night at the earliest.
08-Aug-03	Jan Pritchard		Phone call	Did anyone else submit data? Will send data soon.
08-Aug-03	Sharon Firooz		Phone call	Discussed what SDG&E is going to provide. Has some concerns re: confidentiality. Will send data masked for now.
11-Aug-03	Ben Arikawa	Rod Aoki, James A. Ross	e-mail message	Data in preparation for conference call with Barkovich and Yap
11-Aug-03	Ben Arikawa	Karen Shea, GMC WG	e-mail message	Scheduling of Finance Committee meeting
11-Aug-03	Bert Hansen	Ben Arikawa	e-mail message	comments on notes to August 1, 2003 conference call
11-Aug-03	Dale Yakin		Phone call	Confirmed for him that we only need the %s
11-Aug-03	Rod Aoki		Phone call	Discussed conference call and where we think we are going. Jim will call PG&E to see what data he can get when he gets back from DC later in the week.
11-Aug-03	Rod Aoki, Jim Ross, Barbara Barkovich, Cathy Yap		Phone call	Discussed what to charge for standby load. Discussed Cathy's updates and argued over data. Jim agreed to see if he can get data from PG&E.
12-Aug-03	Sharon Firooz	Ben Arikawa	e-mail message	Revised SDG&E response to ISO information request
12-Aug-03	Sharon Firooz	Ben Arikawa	e-mail message	Correction to August 1, 2003 conference call notes
12-Aug-03	Robert Delgado and Herman Liang		Phone call	Talked about charges, what they are and how they apply.
13-Aug-03	Sharon Firooz	Ben Arikawa	e-mail message	Information on SDG&E monthly load
14-Aug-03	Bert Hansen	Ben Arikawa	e-mail message	Clarification of SCE request to keep some portions of response to information request confidential
14-Aug-03	Dale Yakin	Ben Arikawa, Brian Hitson, Robert Orbeta	e-mail message	PG&E response to the ISO information request
15-Aug-03	Ben Arikawa	Leslie Pompel, Jacqueline De Rosa, David Timson, Phil Leiber, Kim Hubner, Don Wolfe, GMC WG	e-mail message	Response to Ms. Pompel's questions and comments on scheduling charge
15-Aug-03	Leslie Pompel	Kim Hubner	e-mail message	Question on scheduling charge
15-Aug-03	Leslie Pompel	Ben Arikawa	e-mail message	Comments on scheduling charge

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15-Aug-03	David Cohen		Phone call	Discussed timing of ISO report and Finance Committee meeting. What is impact of SCE proposal on other IOUs. What's going on in the Budget process. Will ask for more than three hours for public Budget meeting.
15-Aug-03	Jan Pritchard		Phone call	Discussed status of ISO report and schedule for Finance Committee meeting
18-Aug-03	Ben Arikawa	Robert Delgado, Keoni Almeida	e-mail message	Riverside's billing determinant data
18-Aug-03	Robert Delgado		Phone call	Riverside became a PTO in January, CONG charges rose as a result, but are not reflected in the data used for bill impacts. I sent him all the bds that we have through Feb 03. Quick calculation shows that Riverside would saves some money over the two mon
19-Aug-03	Ben Arikawa	Jan Pritchard, Roger Van Hoy	e-mail message	proposed agenda for meeting
19-Aug-03	Robert Delgado and Herman Leung		Phone call	How does the net deviations work for the ETS and MU? Are we being charged twice? Tried to distinguish between ETS and MU activities. Discussed netting deviations and how that works. Herman brought up losses, who pays for those. Are losses considere
20-Aug-03	Jan Pritchard	Ben Arikawa, GMC WG	e-mail message	Correction to notes on compiled responses to information request
21-Aug-03	Robert Delgado	Ben Arikawa, Keoni Almeida	e-mail message	Request that ISO provide bill impact analysis using updated billing determinants
22-Aug-03	Ben Arikawa	GMC WG	e-mail message	Distributes ISO report on Edison proposed "grid demand" and diversitified demand factors
22-Aug-03	Jan Pritchard	Ben Arikawa	e-mail message	Correction to note is okay with MID
25-Aug-03	Charles Guss	Ben Arikawa	e-mail message	Correction to Anaheim's response to ISO information request
26-Aug-03	David Cohen	Ben Arikawa, Kevin Smith, Mike Brozo, Brian Griess	e-mail message	Questions about the GMC Strategy Group, and the need to update rates given the ISO management's recommendation in the White Paper
26-Aug-03	David Cohen	Ben Arikawa, Phil Leiber, Mike Postar, Kevin Smith	e-mail message	Mr. Cohen requests response to his memo dated February 10, 2003 on more direct assignment of indirects
28-Aug-03	Ben Arikawa	David Cohen, Kevin Smith, Mike Brozo, Bryan Griess, Stephen Morrison, Phil Leiber, Debi Le Vine, William Regan	e-mail message	Response to Mr. Cohen's August 26, 2003 questions
28-Aug-03	Ben Arikawa	David Cohen, Kevin Smith, Mike Postar, Stephen Morrison, Phil Leiber, Debi Le Vine, William Regan	e-mail message	Response to Mr. Cohen's August 26, 2003 questions on indirect assignments
28-Aug-03	Sean Neal	Ben Arikawa, Stephen Morrison	e-mail message	What is the best way to send comments to the ISO Board?
28-Aug-03	Jan Pritchard		Phone call	Discussed avenues for getting documents to ISO Board. MID wants to send comments to Board re: the report.
28-Aug-03	Rod Aoki		Phone call	Discussed ISO's decision not to pursue rehearing of QF PGA
29-Aug-03	Sean Neal	Ben Arikawa, Stephen Morrison	e-mail message	Comments of MID on ISO White Paper
03-Sep-03	Ben Arikawa	Robert Delgado, Keoni Almeida	e-mail message	Bill impacts that Riverside requested
03-Sep-03	Bert Hansen	Ben Arikawa, Jim Cuillier, Jennifer Key, Neil Shockey	e-mail message	SCE comments on ISO White Paper
04-Sep-03	Robert Delgado		Phone call	Had some questions re: bill impacts. Could reproduce billing determinants. Forward scheduling - only HA schedules, not charging for changes to DA schedules Can you run values through June? (no data yet)
05-Sep-03	Rod Aoki	Ben Arikawa	e-mail message	Comments to Finance Committee on ISO white paper of August 22, 2002
05-Sep-03	ISO, MID	ISO Finance Committee	Conference call	Discussion of ISO management report and consideration of changes in rate design

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NOTICE SUITABLE FOR PUBLICATION IN THE FEDERAL REGISTER

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	))	**Docket No. ER04- -000**

Notice of Filing

[ ]

Take notice that on October 31, 2003, the California Independent System Operator Corporation ("ISO") tendered for filing its Grid Management Charge ("GMC") rate. The purpose of the GMC is to allow the ISO to recover its administrative and operating costs. The ISO is requesting that the GMC rate be made effective January 1, 2004.

The ISO states that this filing has been served on the Public Utilities Commission of California, the California Energy Commission, the California Electricity Oversight Board, and upon all parties with effective Scheduling Coordinator Service Agreements under the ISO Tariff.

Any person desiring to be heard to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, D.C. 20426, in accordance with Rules 211 or 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. §§ 385.211 and 385.214). All such motions or protests should be filed on or before [ ]. Protests filed with the Commission will be considered by it in determining the appropriate action to be taken but will not serve to make the protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of this document on compact disc upon the Public Utilities Commission of California, the California Energy Corporation, the California Electricity Oversight Board, and upon all entities with effective Scheduling Coordinator Service Agreements under the California Independent System Operator Tariff.

Dated this 31st day of October in the year 2003 at Washington in the District of Columbia.

Theodore J. Paradise