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Exhibit No. ISO 2(20) [redacted]

October 12, 1999

STEERING COMMITTEE MEETING

[redacted]

[redacted]

[redacted]

CALIFORNIA ISO

California Independent
System Operator

GMC Unbundling Steering Committee Meeting Agenda October 12, 1999

10:00 a.m. – 2:00 p.m. in 101A1a & 1b

10:00 a.m. – 10:15 a.m.	Overview - Expectations
10:15 a.m. – 10:45 a.m.	PJM Unbundling Proposal
10:45 a.m. – 12:30 p.m.	Billing Determinants - Control Area - Scheduling - Market Operations - Billing & Settlements - Congestion
12:30 p.m. – 1:00 p.m.	Lunch
1:00 p.m. – 1:15 p.m.	Considerations - Revenue Stability – Bank Restrictions
1:15 p.m. – 1:45 p.m.	MCI Cost Allocation Overview
1:45 p.m. – 2:00 p.m.	Planning for the Next Meeting

Open discussions of any additional comments are welcome

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GMC Unbundling Steering Committee Meeting
October 12, 1999
10:00 a.m. – 2:00 p.m. in 101A-1a & 1b

Sign-in Sheet

Bent Hansen	SCE
Mike Werner	DWR
[illegible]	CA [illegible]
MICHELLE WINDMILLER	CAISO
Cheryl Beech (call-in)	R.J. Rudden & Associates
Beth Bloom (call-in)	APX
Michele Wynne (call-in)	MZA Grid Services
Jim Price	CPUC
Ed [illegible]	SEMPRA
Raymond Venner	PG&E
Romulo Barreno	CalPX
Bill Regan	CAISO
Mike Epstein	CAISO
Phil Leiber	CAISO
Cathy Young	CAISO
Michael Turner	CAISO
Larry Lau	Calpx
Gene Waas	Calpx
Barbara Barkovich	Barkovich & Yap

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Sign-in Sheet

Brian Jobson	SMUD
Kevin Graves	CAISO
Bill Bojorquez	CAISO
Robert Berry (call-in)	APX
Carolyn Kehrein	Board
David Cohen	Resource Management Intl. Inc./[illegible]
Jim Ross	RCS – Cogeneration Association of Calif.
Charlotte Marth	CAISO

GMC Unbundling Steering Committee
Meeting Notes
10/12/99

Present:

Barbara Barkovich	Barkovich & Yap
Carolyn Kehrein	Board
Michele Wynne (call-in)	MZA Grid Services
Bert Hansen	SCE
Michael Werner	CDWR
David Cohen	TANC/ Resource Management
Jim Ross	RCS/ Cogeneration Assoc. of California
Jim Price	CPUC Office of Ratepayer Advocates
Brian Jobson	SMUD
Robert Berry (call-in)	APX
Beth Bloom (call-in)	APX
Ray Venner	PG & E
Romulo Barreno	PX
Gene Waas	PX
Larry Lau	PX
Ed Lucero	Sempra
Cheryl Beech (call-in)	R.J. Rudden & Associates
Mike Epstein	CAISO
Charlotte Martin	CAISO
Phil Leiber	CAISO
Michelle Windmiller	CAISO
Bill Regan	CAISO
Bill Bojorquez	CAISO
Deanne Nelsen	CAISO
Kevin Graves	CAISO
Cathy Young	CAISO
Michael Turner	CAISO

Introductions were made

Agenda was reviewed

Board calendar was reviewed

Goal: To have a consensus of Billing Determinant Buckets by the November or December Board Meeting.

Discussion of Billing Determinates Buckets (see new attachment)

Discussion of Handouts (see Billing Determinants & Service Category Handouts – emailed and sent out for this meeting)

Other ISO's discussed – i.e. PJM

Ideas: Share costs with generators
Subscription costs

See Impact Analysis (examples are for June)
All agree on gross except one.

Kevin Graves – gross load goal

Revenue Stability - Bank Restrictions

MCI – Michelle Windmiller

Contract Pricing – Monthly Minimum of $2.5Million

ISO Backbone – Bandwidth and WAN Infrastructure Pricing
ISO Network Access Pricing
OC3s
OC12s
ISO Data Premises Pricing
ISO Voice Premises Pricing
ISO Shared Network Services

On-going Contract Negotiations with MCI

-Sell off excess transmission to offset costs?
-Auction?

The Next meeting is set for Tuesday, November 30th, 1999

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Billing Determinant and Service Category Overview

California ISO: Service Category	% Rev Req	CPUC	CDWR	APX	MZA	Examples	PJM: Service Category	% Rev Req	ISO New England: Service Category
Control Area Operations	35%	Control Area Metered Load in MWh	Control Area Metered Loads & Exports in MWh	Control Area Metered Loads in MWh	Control Area Metered Loads & Exports in MWh	Control Area Metered Load & Exports in MWh	**Control Area Services:** Control Area Metered Loads & External Transactions in MWh	42%	**Reliability Administration Service (RAS):** Participant Customers 55% of monthly RAS costs based on Load in MWh & 45% of monthly RAS costs based on Generation Ownership Shares
Real Time Energy Balancing	-	Deviations from scheduled load		Deviations from scheduled load			**Regulation and Frequency Response Service:** Sign on fee of $30K, then, rate based on Regulation obligation of Load Serving Entity + Regulation Scheduled (paid by generator)	2%	
							Capacity Adequacy Service (Similar to RMR): Daily capacity obligation of each load serving entity in MW within the control area	4%	
							Capacity Resource & Obligation Management: Sign on fee of $60K then, allocate remainder based on Daily capacity Obligation of LSE in Mwh, & Generator capacity in MWh.	4%	
Scheduling	11%	Scheduled loads	Controlled Grid Metered Loads & Exports	Scheduled loads	Schedule Templates submitted or Fixed fee for base & per template charge over the base	Controlled Grid Metered Loads & Exports in MWh	**Internal Energy Transactions Service:** Sign on Fee of $72K, then, monthly subscription fee per company.	1%	
							Point to Point & Network Import Transmission Service Administration: MW transmission service reserved	10%	**RAS: Point-to-Point Transmission Services:** Non-Participant Transmission Customers - $500 monthly for Monthly or Annual Service + $115.38 weekly for Weekly Service + $23.07 daily for for Firm Daily Service + $16.47 daily for Non-Firm Daily Service + $0.69 hourly for Non-Firm Hourly Service
Congestion	7%	Interzonal scheduled load	Controlled Grid Metered Loads and Exports excluding ETCs and FTRs	Controlled Grid Metered Loads	To TOs	Congestion Charges in MWH			
							Fixed Transmission Rights: FTE MWh Granted	4%	
Market Operations	23%	Traded volume	All transmission uses in Control Area with factors by customer class (buy & sell = 1; sell or buy = 0.5; sell providors = 0.25)	Traded volume in MWh	MWh of A/S not self provided	A/S & Real Time traded volume in MWh	**Market Support Service:** Load in MWh + External Transactions in MWh + Generation in Mwh	33%	**Energy Administration Service:** Electrical Load in KWh + Customers Ownership Shares in KWh
Market Information & Surveillance	-	Metered load and/or transaction charge		Metered loads					
Billing, Metering & Settlement	24%	Metered load and/or transaction charge	Control Area metered loads with factors by customer class (buy & sell = 1; sell or buy = 0.5, sell providors = 0.25)	Metered loads	Part billed on # of SQ meter data items submitted & part billed on # of statement line	A/S, Real Time & Congestion billed volume in MWh			

APX Recommendations for GMC Cost Allocation

General Considerations:

APX notes that in making its selection of billing determinants the cost allocation exercise should not focus only on a short run perspective but also consider the long run perspective on which the ISO sized its systems. APX also notes that many of the ISO costs are common costs and that this makes the allocation process imprecise. Moreover, this imprecision means that cost allocation can become a contentious activity, which implies favoring a common allocation or billing determinant to limit this contention. APX believes that recognition of these factors favors using MWhs of metered or scheduled load in most areas.

Control Area Operations

Recommended Billing Determinant: Metered load in MWhs because most of the services in this category are provided to all metered load across the system. As ORA noted, some activities such as real time energy balancing can be allocated based on load deviations.

Scheduling

Recommended Billing Determinant: Scheduled load in MWhs because this is the activity measure directly associated with this function.

Congestion

Recommended Billing Determinant: Metered load in MWhs which more likely describes the long run sizing and cost of the activity in this area.

Market Operations

Recommended Billing Determinant: Traded volumes in MWhs for the activity of conducting of the ancillary service auctions because this measures the extent to which ISO participants use this service. As ORA noted, posting of market information and market surveillance are more properly allocated to all metered load.

Settlements and Billing

Recommended Billing Determinant: Metered loads in MWhs, which more likely describes the long run sizing and cost of the activity in this area.

MZA Grid Services Suggestions for allocating GMC:

1. **Grid Operations: by metered demand and exports**. Grid Ops are utilized by all participants and this option allocates the cost to the ultimate purchaser. Another option is to suppliers and imports but the cost will be passed to the purchaser anyway.

2. **Scheduling: by schedule templates submitted**. MZA assumes that the more schedules managed the greater the cost to the ISO. An option is a fixed fee for a predetermined number of templates submitted and tiers above that but that adds complexity.

3. **Congestion: to the transmission owners.** If the Cal ISO system was designed like other control areas, participants would be required to have transmission rights prior to scheduling. Congestion caused by derates are the responsibility of the TO whose tariff is suppose to cover maintaining the lines.

4. **Market Functions: by megawatthours of the A/S obligation not self-provided.** The A/S market is a service run by the ISO for those participants who do not or can not self provide.

5. **Settlement and Billing: by number of Settlement Quality meter data items submitted and the number of line items on the bill.** The ISO settlement process not only performs settlement for grid level activities but also acts as the distribution consumption meter settler for the CPUC regulated customer unbundling process. Having a portion of the GMC for settlements billed by the number of SQ meter data items submitted will better reflect the cost of the ISO managing a distribution level function. Having a portion of the settlement GMC allocated by number of line items reflects MZA's assumption that the more line items the greater the cost.

August 12, 1999

The following are the Department of Water Resources' initial comments on the Grid Management Charge unbundling proposals and material provided July 19, 1999:

Control Area Operations:

DWR would support charging CAO to ALL loads within the ISO Control AREA on a gross basis on MWh of metered energy consumption. DWR also would support charging exports for CAO.

Scheduling:

DWR would support charging Scheduling to all loads within the ISO Control Grid on a gross basis on MWh of metered energy consumption. RPTOs that act as the SC for an ETC should be billed Scheduling for the ETCs. DWR would support charging exports for Scheduling.

Congestion:

DWR would support charging Congestion to all loads within the ISO Control Grid on a gross basis on MWh of metered energy consumption. DWR would oppose billing congestion to schedules using ETCs or FTRs. DWR would oppose limiting Congestion charges to just Interzonal schedules (more discussion is needed on this point).

Market Operations:

DWR believes that the ISO achieves Control Area reliability through Market Operations. Thus it would support charging Market Operations to all transmission uses within the ISO Control AREA. In doing so, DWR would support use of a multi-tiered structure that would use adjustment factors or multipliers for various classes of entities, depending upon their participation in the market. Entities that are fully in the market and buy and sell all A/S through the market would have a multiplier of 1.0. Entities partially in the market (sell but do not buy A/S) would have a multiplier along the lines of .5. Lastly, Entities that do not participate in the market and which self-provide would have a multiplier along the lines of .10 to .25. DWR would also support billing both loads and generation for Market Operations in order to spread these costs to entities that sell A/S to the ISO but have little or no purchases of A/S.

Billing, Metering & Settlements:

DWR would support billing BM&S to all loads within the ISO Control Area on a MWh of metered consumption basis using a multi-tiered structure similar to that proposed above, based upon their level of participation in the ISO.