UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

GRID MANAGEMENT CHARGE

VOLUME VII OF IX

- Exhibit Numbers ISO-177 through ISO-265

October 31, 2003

From: CRCommunications
Sent: Thursday, February 06, 2003 10:07 AM
To: ISO Market Participants
Subject: CAISO Notice - Stakeholder Meeting - 2004 GMC Rate Structure Project

MARKET NOTICE

February 6, 2003

In Re:

FERC Decision in ER01- 313- 000, Settlement in ER02- 250- 000
Stakeholder Meeting - 2004 GMC Rate Structure Project

ISO Market Participants:

On February 19, 2003 the California ISO ("ISO") will hold a further stakeholder meeting as part of the 2004 Grid Management Charge ("GMC") Rate Structure Project. The meeting will be from 9:30 a.m. to 3:00 p.m. at the headquarters of PG&E in San Francisco.

Background

Following Judicial direction from the Federal Regulatory Energy Commission, the ISO, initiated the "2004 GMC Rate Structure Project" in mid-summer 2002 to review comprehensively the existing GMC structure and to develop a new GMC rate structure to be in place by January 2004. This review is open to all stakeholders and has involved the active participation of a number of entities thus far. In past meetings, participants and the ISO have reviewed the structure of stakeholder participation, rate structures of other ISOs, FERC Staff views on ISO rates as a formula rate, various rate methodologies, ISO activities and data requirements for development of rate proposals.

The next Project meeting will be on February 19, 2003 as noted above. Additional information regarding past Project activities is accessible in the ISO web site at:

<<http://www.caiso.com/docs/2002/08/02/2002080216283419989.html>>

Process Moving Forward

The ISO expects participants in the Project to provide input on various rate design elements in order to assist the ISO in developing a revised GMC structure and methodology. The ISO will also ask participants to present their own rate structure proposals.

Specifically: at the February 19th meeting, parties will be asked to present their conceptual rate proposals. As of the date of this market notice, two entities have put forth written proposals. These entities, Modesto Irrigation District and Southern California Edison, and the ISO will make presentations on its conceptual rate proposals. Other parties are also hereby encouraged to make presentations.

As the Project moves forward, the ISO emphasizes that this is an open Project and encourages participation from entities that have not yet contributed.

If you would like to attend the February 19th meeting, please RSVP to Michelle Gamble (mgamble@caiso.com <mailto:mgamble@caiso.com> <<mailto:mgamble@caiso.com>> or (916) 351-2118) by 5:00 PM on February 12th.

The agenda, presentation materials and meeting location specifics will be emailed to those on the GMC WG distribution list prior to the meeting.

If you would like to be placed on the distribution list for announcements and documents for the 2004 GMC Rate Structure Project, please email Michelle at the address above. Please ask to be added to the ISO's "GMC WG" e-mail distribution list.

Client Relations Communications.0921
CRCommunications@caiso.com <mailto:CRCommunications@caiso.com>

Draft

2004 GMC Rate Structure Project Briefing

To: Participants in 2004 GMC Rate Structure Project

From: Ben T. Arikawa, Senior Financial Analyst

Date: February 7, 2003

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

This Briefing contains information about the next 2004 GMC Rate Structure Project meeting in San Francisco, the series of conference calls that have been held with the Modesto Irrigation District (MID), data availability, ISO analysis of ETC system costs, the customer classes to be used for rate impact analysis, the groupings of activities and the GMC Tool.

Wednesday, February 19, 2003 GMC meeting information

As I wrote last week, PG&E has graciously offered to host the next meeting on February 19, 2003 in San Francisco.

Meeting information is as follows:

Room 301B
77 Beale Street
San Francisco
9:30 – 3:00 (PST)
Call in number 1-888-788-6681
Pass code 921065

If you plan to attend this meeting, please RVSP to Michelle Gamble, mgamble@caiso.com, by close of business Wednesday, February 12, 2003. An RVSP will assist PG&E in maintaining security and will allow you to get through PG&E security more easily. Lunch will be provided.

If you have asked for one of the parking spots in PG&E's facilities, please include the make, model and license number of your vehicle when you RSVP. PG&E's parking facility is located at 50 Main Street, which is around the block from the Beale Street address.

An agenda and meeting materials will be e-mailed within the next week. As of this date, Southern California Edison, Modesto Irrigation District and the ISO are scheduled to present their conceptual rate proposals at this meeting. If your company has a proposal to present, please let us know as soon as possible so that we may allot time during the meeting for discussion. Also, please provide a written summary of your proposal by close of business February 13th, so that we may distribute it before the meeting.

Conference calls with MID on assignment of costs to MID functions

As of Friday, February 6, 2003, the ISO and MID have had four conference calls to discuss the assignment of costs to MID functions. The dates of these calls and the topics discussed were:

Date	Topic
Monday, February 3, 2003	Grid Operations direct assignments
Tuesday, February 4, 2003	MD02 and bond and cash financed capital expenditures
Wednesday, February 05, 2003	Market Analysis and Compliance
Friday, February 7, 2003	Information Services

An additional conference call has been scheduled for Monday, February 10, 2003 from 9:30 to 11:30 on Market Services direct assignments. The call in number and pass code are the same as those listed for the February 19th meeting.

MID distributed a spreadsheet containing the cost assignments made thus far to the GMC WG just after noon today.

These calls are open to all to listen in. However, we request that parties on the phone respect the specific purpose of the call: to allow MID the ability to understand ISO cost center activities sufficiently to assign costs to their three functions.

Data availability

On Friday, January 31, 2003, we had distributed the complete list of aggregated billing determinant data. If you have not received this data, please let me know and I will resend it. As of this date, we have received no requests for other types of billing determinant data.

The deviation data MID requested is available for those that have signed the Confidentiality Agreement and the Non-Disclosure Certificate. As of today, the EOB, CAC, PG&E, and David Cohen have requested the data. If you wish to have a copy of the data, please e-mail me with your street address and telephone number so that we can send this information to you by Federal Express.

Finally, the ISO modified the Cost Allocation Matrix to incorporate MID's ISO functions. There are some errors in the modifications created for MID, which will be fixed in a subsequent version. This spreadsheet is available to those that have signed the Confidentiality Agreement and the Non-Disclosure Certificate.

System costs of administration of ETCs

As requested by the CPUC at the January 13th GMC meeting, we are attempting to determine of the system costs of administering ETCs under MD02. This should be completed within the next week and will be distributed to the GMC WG e-mail distribution list.

Preliminary assignment of SCs to customer classes

For the purpose of determining customer impacts, we have begun to assign SC IDs to the following customer categories:

- IOU;
- Governmental entity;
- QF volumes; and,

- Other.

A preliminary mapping of SC IDs to these customer classes was e-mailed on February 5, 2003. We ask that you provide your comments on this mapping or an alternative by February 12, 2003. We hope to finalize this list at the February 19th meeting.

Groupings of Activities

As of this date, the ISO has not received written comments on (with the exception of MID) or requests for changes to the "Preliminary Groupings of Activities for ISO Rate Structure." The last version of this document is dated December 19, 2002 and was distributed for a December 23, 2002 conference call. In order to continue development of the GMC Tool (see below), we need to finalize the groupings of activities. If you have comments or requests for changes, please let me know as soon as possible, but no later than close of business February 12th. We will distribute and post a final version on the GMC web page prior to the next meeting on February 19th.

GMC Tool

As requested by David Cohen, the ISO has begun development of a GMC Tool that would allow a user to develop a rate structure using the groupings of activities and aggregated billing determinant data. This tool could incorporate customer class information and be used to show impact analysis of different rate structures. We will demonstrate a prototype of this Tool at the February 19th meeting and ask for your comments on its form and function.

If you have any questions about any of the information contained in this memorandum or about the process, please do not hesitate to contact me by phone, (916) 608-5958, or e-mail at barikawa@caiso.com.

Note: This document is circulated by the sender solely for the express purpose of informing discussion. Therefore, none of the contents may be regarded by the reader as any form of offer, undertaking, policy, proposal or commitment by the sender, author or the California ISO.

Department 1731 02-10-03.txt

From: lkirsch@svn.net
Sent: Monday, February 10, 2003 7:44 PM
To: dlevine@caiso.com
Cc: BArikawa@caiso.com; rchemphill@lrca.com
Subject: Department 1731

Debi:

Ben left me a message saying that you would like to speak with Ross and I about Department 1731, but that you will not be available until next week. Because the GMC meeting in San Francisco occurs on Wednesday morning, and because I have prior obligations on Monday, I would like to suggest that Tuesday would be the ideal day fin the IS□□s □2004 Rate Structure Proj prior to 3 pm PST will work (since Ross is in the Midwest), though I would prefer earlier in the day.

Please let me know what time on Tuesday is most convenient for you. If Tuesday is not possible, please suggest an alternate day.

Thanks for helping us with this.

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

****

Revised CAM and Cost Center 14241441 detail 02-12-03.txt
From: Arikawa, Ben
Sent: Wednesday, February 12, 2003 11:46 AM
To: Kirsch, Laurence
Subject: Revised CAM and Cost Center 1424/1441 detail

Attached are a revised Cost Allocation Matrix which was previously sen
t
to you on January 16, 2003. This version corrects cell references and

provides some annotation of assignment methods used for some cost centers. I have also incorporated MID's cost assignments as of February 7, 2003.

The other attachment is provided to you per your request for more detail concerning the costs within cost centers 1424 and 1441. There is a "breakout" of costs for systems provided in addition to subaccoun
t
information.

If you have any questions, please do not hesitate to contact me.

These materials are provided subject to the Confidentiality Agreement and the Non-disclosure Certificate. (See disclaimers provided within each spreadsheet.)

Note: The information attached is intended for the designated recipients only and is provided solely for the purpose of furthering discussion and research in the ISO's '2004 Rate Structure Project'. The information, in the form attached, is provided in response to Stakeholders' requests and as such does not necessarily indicate the ISO's concurrence in, or support for, its usefulness in developing a rate methodology. No implications may be drawn regarding the ISO's position on any subject in the Project from either the inclusion or exclusion of any specific data. The ISO does not warrant the completeness or accuracy of the data. The ISO is not necessarily the originator of the data.

Ben Arikawa
Senior Financial Analyst
California Independent System Operator
151 Blue Ravine Road
Folsom, CA 95630

Voice: (916) 608-5958
fax: (916) 351-2259

email: barikawa@caiso.com

Revised CAM and Cost Center 14241441 detail 02-12-03.txt

2004 GMC Rate Structure Project Briefing

To: Participants in 2004 GMC Rate Structure Project

From: Ben T. Arikawa, Senior Financial Analyst

Date: February 14, 2003

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

This Briefing contains information about the next 2004 GMC Rate Structure Project meeting in San Francisco, agenda and documents for that meeting, the last of the series of conference calls that have been held with the Modesto Irrigation District (MID) and data availability.

Wednesday, February 19, 2003 GMC meeting information

Meeting information is as follows:

Room 301B
77 Beale Street
San Francisco
9:30 – 3:00 (PST)
Call in number 1-888-788-6681
Pass code 921065

PG&E is supplying lunch. If you plan to attend this meeting and have not responded yet, please RVSP to Michelle Gamble, mgamble@caiso.com, as soon as possible. Once you are on-site, you will need to check in with the guard. If you have any problems, please call Lavina Tam (415) 973-6107.

If you have asked for reserved parking in PG&E's garage, these are directions:

- Take Hwy 80 West towards **San Francisco**
- Cross the Bay Bridge ($2 toll to cross bridge.)
- Take **Harrison St.** Exit. (This exit is on the LEFT lane after bridge.)
- Turn RIGHT on **Harrison St.**
- Turn LEFT on Main St.
- Go 3 1/2 blocks down. (Go 1/2 block further once cross Mission St.)
- **50 Main St.** parking **entrance** is on the **Left-side**
- Give parking attendant driver's name

Created By: Ben Arikawa

LST UPDT: 02/13/03

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To get from the parking lot to 77 Beale Street:

- Make a **Right** at Parking Lot exit onto **Main St.**
- Go to end of block. Turn **Right** at **Mission St.**
- At next block, make a **Right** at **Beale St.**
- Walk a 1/2 block. Turn **Right** at the open area between the 2 high-rise buildings,
- **77 Beale St.** is the building on the **Right.** (It's the building with 4 sets of doors).

An agenda are attached and will be posted on the ISO GMC web page. Attached in a zipped file are a prototype of the GMC Tool, the "Preliminary List of Groupings of Activities, " SCE's rate proposal, a presentation on the ISO's conceptual rate proposal, and a proposed agenda. In a separate zipped file, we have included detail on what type of information is included in the Budget Tool. Dr. Kirsch will send out a copy of his presentation early next week. We will forward it to the GMC WG.

Also attached is a memorandum from CDWR-SWP regarding the development of customer classes. This will be discussed during the meeting.

PG&E will have an overhead projector and a projector into which you can plug a laptop for viewing of presentations.

Conference calls to discuss rate proposals

Given the number of items on the agenda and the need to allow reasonable time for parties to ask and respond to questions, the ISO proposes to have at least one follow-up conference call during the week of February 24th for this purpose. We will discuss this during the meeting on Wednesday.

Conference calls with MID on assignment of costs to MID functions

As of Monday, February 10, 2003, the ISO and MID have had five conference calls to discuss the assignment of costs to MID functions. The dates of these calls and the topics discussed were:

Date	Topic
Monday, February 3, 2003	Grid Operations direct assignments
Tuesday, February 4, 2003	MD02 and bond and cash financed capital expenditur
Wednesday, February 05, 2003	Market Analysis and Compliance
Friday, February 7, 2003	Information Services
Monday, February 10, 2003	Market Services

No further conference calls concerning MID's proposal are currently scheduled, though MID may call individual ISO staff with follow-up questions.

Data availability

On Friday, January 31, 2003, we had distributed the complete list of aggregated billing determinant data. If you have not received this data, please let me know and I will resend it.

The deviation data MID requested is available for those that have signed the Confidentiality Agreement and the Non-Disclosure Certificate. As of today, the EOB, CAC, PG&E, and Navigant Consulting have requested the

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data. If you wish to have a copy of the data, please e-mail me with your street address and telephone number so that we can send this information to you by Federal Express.

This week, the ISO provided two documents to assist MID in development of its rate proposal. The first was a revised modified Cost Allocation Matrix, which incorporated MID's ISO functions. The second was a more detailed accounting of costs by sub-account in cost centers 1424 and 1441. In addition to MID, NCPA, the EOB, and Navigant Consulting requested copies of these spreadsheets. These spreadsheets are available to those that have signed the Confidentiality Agreement and the Non-Disclosure Certificate.

If you have any questions about any of the information contained in this memorandum or about the process, please do not hesitate to contact me by phone, (916) 608-5958, or e-mail at barikawa@caiso.com.

Note: This document is circulated by the sender solely for the express purpose of informing discussion. Therefore, none of the contents may be regarded by the reader as any form of offer, undertaking, policy, proposal or commitment by the sender, author or the California ISO.

RE My Presentation for Wednesday 02-18-03.txt

From: Arikawa, Ben
Sent: Tuesday, February 18, 2003 11:14 AM
To: 'lkirsch@svn.net'; Arikawa, Ben
Cc: Leiber, Phil; Pritchard, Jan; rchemphill@lrca.com
Subject: RE: My Presentation for Wednesday

Laurence,

Thank you. I will forward this to the GMC WG and have it posted to th
e
website. Debi LeVine will be at the meeting tomorrow. It may be
you'll have time to talk then.

Ben Arikawa
Senior Financial Analyst
California Independent System Operator
151 Blue Ravine Road
Folsom, CA 95630

Voice: (916) 608-5958
fax: (916) 351-2259

email: barikawa@caiso.com

-----Original Message-----
From: lkirsch@svn.net [mailto:lkirsch@svn.net]
Sent: Tuesday, February 18, 2003 9:37 AM
To: BArikawa@caiso.com
Cc: PLeiber@caiso.com; janp@mid.org; rchemphill@lrca.com
Subject: My Presentation for Wednesday

Please see the attached PowerPoint file.
****
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 Independent
System Operator

Proposed Agenda
2004 GMC Stakeholder Process
February 19, 2003
9:30 a.m. to 3:00 p.m.
PG&E Headquarters
Room 301B
77 Beale Street
San Francisco, CA
Conference Call-in #888-788-6681
Passcode: 921065

Introductions/Announcements	9:30
Edison Rate Proposal	9:35
Break	10:35
MID Rate Proposal	10:45
GMC Tool Prototype	11:45
Lunch	12:00
ISO Conceptual Rate Proposal	12:30
Discussion of billing determinants	1:30
Discussion of grouping of activities	1:45
Break	2:00
Review of MID/ISO conference calls	2:10
Mapping of SC IDs to customer classes	2:15
Budget Tool	2:45
Miscellaneous Items (Discussion of indirect assignments, public discussion page on ISO GMC web page, follow-up conference calls, next meeting)	2:55

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></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></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><th>CAS</th><th>DDES</th><th></th><th>SS</th><th>MOS</th><th>RMOS</th></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.

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[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:

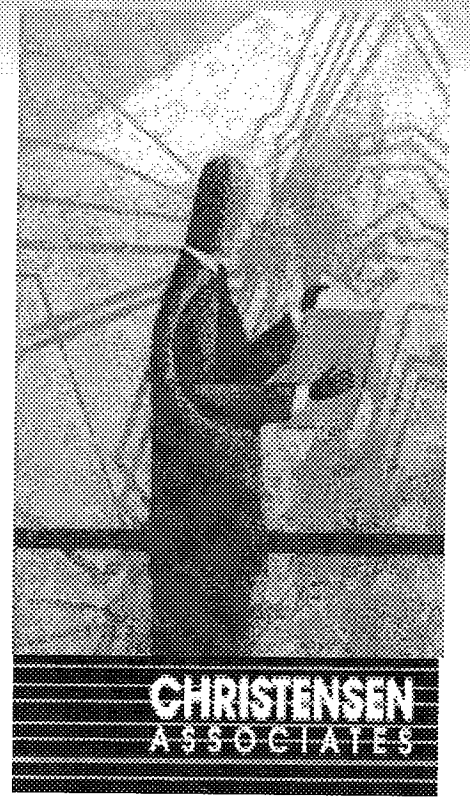
Scheduling Service Revenues of $12 (Rate of $0.10 times 120 MWh)
Market Operations Service Revenues of $51 (Rate of $0.85 times 60 MWh)
Real-Time Market Operations Service Revenues of $37 (Rate of $1.85 times 20 MWh)

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



Progress in Quantifying Modesto's GMC Proposal

Laurence D. Kirsch
Laurits R. Christensen Associates, Inc.
www.LRCA.com

CAISO 2004 GMC Rate Design Project Meeting

San Francisco, California
February 19, 2003

Exh. No. ISO- 185, Page 1 of 24

Topics

- Engineering Foundations
- Our Proposed Functions
- Progress in Quantifying Our Proposal

Exh. No. ISO- 185, Page 2 of 24

Engineering Foundations

Exh. No. ISO- 185, Page 3 of 24

System Operators Minimize Costs Subject to Constraints

- System Constraints:
  - power balance
  - transmission flow limits
  - voltage limits
- Private Constraints:
  - generator output limits
  - generator ramping limits

Exh. No. ISO- 185, Page 4 of 24

A Few References (1)

- 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. (U of Texas)
- 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. (Indira Gandhi Inst. of Development Research)
- 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. (Jeonju U (Korea), KEPCO (Korea), Seoul National U)
- 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. (Zhejiang U, U of Hong Kong)

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A Few References (2)

- W.W. Hogan, "Markets in Real Electric Networks Require Reactive Prices," *Energy Journal*, 14(3): 171-200, 1993. (Harvard U)
- 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. (Technical U of Nova Scotia)
- 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. (Federal U of Maranhao (Brazil))

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Our Proposed Functions

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Criteria for Our Choice of Functions

- Relevance to the System Operator's Job:
  - The system operator manages system constraints.
  - Participants manage private constraints.
- Measurability:
  - Customers' use of power balancing and flow management services is measurable.
  - Their use of voltage control service is not measurable.
- Supplemental Services:
  - Scheduling (helps balancing and flow management)
  - Administering markets (helps balancing)

The functions are the same with or without MD02.

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Our Proposed Functions

- Resolving Energy Imbalances
- Managing Transmission Flows
- Administering Markets
- Scheduling Generators, Loads, and Transmission Facilities

Exh. No. ISO- 185, Page 9 of 24

Resolving Energy Imbalances (1)

- This function assures that resources approximate loads (including losses) at every instant.
- Advance activities include:
  - performing operation studies
  - conducting system security analyses
  - conducting system planning studies
  - determining and enforcing regulation and reserve requirements

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Resolving Energy Imbalances (2)

- Near real-time activities include:
  - integrating ISO operations with those of other control areas
  - coordinating facility outages
  - scheduling and dispatching generation, imports, exports and wheeling;
  - some settlement, billing, and metering costs
- This function does *not* include:
  - market-making activities that allow market participants to resolve their own imbalances before real-time.

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Managing Transmission Flows (1)

- This function assures that transmission flows do not exceed transmission capabilities.
- Advance activities include:
  - performing operation studies
  - conducting system security analyses
  - fostering transmission maintenance standards
  - conducting system planning studies
  - planning transmission

Exh. No. ISO- 185, Page 12 of 24

Managing Transmission Flows (2)

- Near real-time activities include:
  - integrating ISO operations with those of other control areas
  - coordinating facility outages
  - scheduling and dispatching generation, imports, exports, and wheeling
- Costs that are not related to the other functions are deemed to fall within this function.

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Administering Markets

- This function allows market participants to enter voluntary energy or ancillary services trades with one another in advance of real time.
  - In principle, equivalent trading services could be provided by independent brokers
- Costs are those of:
  - the hardware, software, communications, and personnel systems required to support trades
  - some settlement, billing, and metering costs
  - market monitoring services

Exh. No. ISO- 185, Page 14 of 24

Scheduling Generators, Loads, and Transmission Facilities

- This function allows SCs to change their schedules.
- Its costs are the ISO's incremental costs of schedule changes.
  - Includes the capital, labor, and operations costs of having facilities and staff available to provide this service.

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Mapping of ISO Rate Groups to MID Functions

FROM	TO			
	Resolving Energy Imbalances	Managing Transmission Flows	Administering Markets	Scheduling
Control Area Services	✓	✓		✓
Congestion Management		✓		
Market Operations / ASREO	✓		✓	

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Progress in Quantifying Our Proposal

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Summary of Progress

Step	Done	Almost Done	Simple Calculation	Assumed Value
1		✓		
2	✓			
3			✓	
4	✓			
5	✓			
6	✓			
7			✓	
8				✓
9			✓	

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Progress by Steps (1)

- Step 1. Assign Costs to Functions
  - Near the end of collaborating with the ISO on direct assignments
  - Need ISO to compute indirects and totals
- Step 2. Forecast Test Year Power Withdrawals from the ISO-Controlled Grid
  - The ISO has done this.

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Progress by Steps (2)

- Step 3. Set the GMC Price for Power Withdrawals from the ISO-Controlled Grid
  - This is a simple calculation from the results of Steps 1 and 2.
- Step 4. Assemble Historical Data on Uninstructed Energy Imbalances
  - The ISO has done this.

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Progress by Steps (3)

- Step 5. Calculate Covariances of Uninstructed Energy Imbalances
  - We have done this.
- Step 6. Calculate the "Ideal Cost Allocation" of Energy Imbalance Charges
  - We have done this.

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Progress by Steps (4)

- Step 7. Determine Preliminary Prices on Energy Imbalances
  - This is a simple calculation from the results of Steps 1 and 6.
- Step 8. Forecast Test Year Energy Imbalances
  - We will assume they equal historical imbalances.

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Progress by Steps (4)

- Step 9. Determine Prices on Energy Imbalances
  - This is a simple calculation from the results of Steps 7 and 8.

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Next Steps

- Complete our results:
  - Finalize cost assignment
    - Get breakdown on Department 1731
    - Calculate indirects
  - Perform final calculations
- Present rate design to ISO

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Navigant™
CONSULTING, INC.

MEMORANDUM

DATE: February 10, 2003

TO: Ben Arikawa, Phil Leiber

FROM: David B. Cohen

SUBJECT: CAISO INDIRECT COSTS

Note: This document was prepared for the express purpose of starting a discussion and furthering the evaluation. Therefore, none of the contents may be regarded by the reader as any form of offer, undertaking, policy, proposal or commitment by the sender.

2004 GMC Rate Structure Project[1] -
a Stakeholder Process

The 2004 GMC Rate Structure Project is being performed in part to respond to the FERC Administrative Law Judge's 2001 GMC Initial Decision (ID) in ER01-313-000. In the ID the ALJ stated, "Rather, the entire GMC should be examined in totality and any restructuring or reallocations should be proposed and implemented in that overall context." [ID at page 50]. During the course of the hearing "The ISO agrees that there is always room for improvement, and the ISO is willing to entertain improvements in subsequent budget iterations. *Id.* 49:21-50:20".

A tool to assist the 2004 GMC Rate Structure Project is using the 2003 GMC Budget and Cost Allocation Matrix (CAM) for informational and discussion purposes. Examining the CAISO's 2003 Budget, reveals approximately $60 million out of $171.7 million of Operating Expenses (or 35 percent) are identified as Indirect Costs.

As part of a 2004 GMC Rate Structure Project there needs to be examination of all Cost Centers (Direct and Indirect) to determine if breakdown of previously identified Indirect costs can be achieved as part of the review that is being undertaken. The attached table identifies the Indirect Operating Costs in the 2003 CAISO Budget.
The CAISO Staff should have two working sessions in the latter part of February or early March 2003 to review all Indirect Cost Centers, with Stakeholders, to find out if further direct assignments to cost centers are reasonable.

Please advise all stakeholders of how the CAISO plans to address this issue.

---

[1] Rate Structure includes: determination of services provided (current and future), accumulation of overall costs, cost allocation, rate design (including billing determinants). While not the primary focus of this group, the overall level of ISO costs (also referred to as the ISO revenue requirement) is of concern to ISO stakeholders, and consideration of a mechanism to adequately address this issue prospectively may be necessary.

ISO DEPT #	OPERATING COSTS	TOTAL COSTS
1500	Operations - Indirect Costs	
1511	VP Grid Operations - General	$1,011,957
1547	Engineering and Maintenance - General	$1,154,222
1548	OSAT	$267,932
1564	Operations Scheduling - General	$322,862
Total Operations Indirect Costs		$2,756,973
1700	Market Services - Indirect Costs	
1711	VP Market Services - General	$248,117
1721	Billing and Settlements-General	$353,911
1751	Market Operations - General	$959,968
Total Market Services Indirect Costs		$1,561,996
1400	VP Information Services Indirect Costs	
1411	Chief Information Officer- General	$212,246
	Corporate & Enterprise Applications -	
1422	General	$248,320
1466	Enterprise Applications	$816,499
1431	End User Support	$6,565,001
1432	Computer Operations - General	$430,975
1433	Network Operations	$1,629,905
1442	Production Support	$2,581,165
1451	Information Security	$1,509,500
1463	Operations Applications - General	$323,539
1471	IT Planning	$770,116
1468	Corporate Application Support	$1,333,287
1469	Analytical and Reporting	$1,055,106
1481	Markets and Scheduling	$1,520,628
Total IS Indirect Costs		$18,996,287

ISO DEPT #	OPERATING COSTS	TOTAL COST
1300	Finance - Corporate Indirect Costs	
1321	Accounting	$2,168,530
1331	Financial Planning and Treasury	$2,511,009
1351	Facilities	$5,812,962
1361	Office Administration	$2,227,171
Total Finance Indirect Costs		$12,719,672
1311	CFO - General	$424,204
1631	Legal and Regulatory	$13,118,010
1611	VP General Counsel - General	$385,985
1821	Communications	$865,811
1831	Strategic Development	$693,745
1851	Project Office	$657,758
1861	Regulatory Policy	$1,430,767
Total Corporate and Strategic Devpt b/f HR		$3,648,081
1811	VP Corporate and Strategic Development - General	$497,434
1100/1200	CEO / Human Resources - Corporate Indirects	
1111	CEO - General	$730,899
1841	Human Resources	$4,794,842
1651	Board of Governors	$163,100
Total CEO/HR Costs		$5,688,841
	TOTAL INDIRECT COSTS	**$59,797,483**

CALIFORNIA ISO

California Independent
System Operator

ISO Conceptual Rate Structure

February 19, 2003

2004 GMC Rate Structure Project

Presented by: Phil Leiber

The information in this presentation is preliminary and does not represent the fully developed view of the ISO as to an appropriate GMC rate structure. It was compiled solely for the purpose of furthering discussion and research related to the ISO's '2004 GMC Rate Structure Project'. No implications may be drawn regarding the ISO's ultimate position on any subject in the Project from either the inclusion or exclusion of any specific information in this document.

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Introductory Comments

- **Objectives**
  - Fulfill project objectives as set forth in project charter.
  - Listen to, and incorporate to the extent feasible, ideas raised by stakeholders in GMC process

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Introductory Comments

- **Current ISO Conceptual Rate Structure**
  - Starting point only.
    - Has not undergone extensive internal ISO review.
    - Final version may look significantly different.
    - ISO "still listening" & "still thinking"
      - Still want to see what other parties propose.
  - Does not preclude additional changes.

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CALIFORNIA ISO

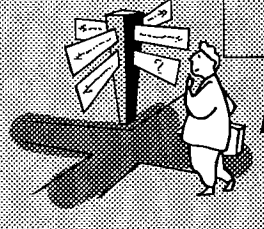
California Independent System Operator

ISO Conceptual Rate Structure

Total Revenue Requirement of ~$240 million

CURRENT	***CAS***	***CONG***	***ASREO***

2004	***Reliability Services***		***Market Services***		***Customer Service***
	Core Reliability Services	**Energy and Transmission Services**	**Market Infrastructure**	**Market Usage**	
	1	***2***	***3***	***4***	***5***



Notes: ***A.*** *New service category names yet to be determined. The above are merely placeholders.*
B. *Sizes of boxes do not necessarily represent the proportion of total ISO costs that each may contain.*
C. *Potential billing determinants discussed on subsequent pages could be used singularly or in combination for each service category/subcategory.*

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1. RS: Core Reliability Services

- Conceptual Description:
  - Core functions essential to the existence of a functioning control area. The minimum staffing, software and facilities necessary to operate a bare-bones control area (as geographically dispersed as the present system but with minimal load). Example: requires five shifts for control room operators, two physical locations to ensure reliability in case of major catastrophe.
- ***Potential*** Billing Determinants

Coincident demand, gross or net	Demand
Maximum **non-diversified,** non-coincident demand, gross or net	Demand
Maximum **diversified** non-coincident demand, gross or net	Demand
Monthly gross control area load (energy) plus exports	Volumetric

Others?

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2. RS: Energy & Trans. Services

- Conceptual Description:
  - Services performed in a control area operation that fluctuate according to the intensity of use within the control area. This includes the services for simultaneously managing the energy imbalances and the transmission flows in excess of core control area requirements.
- ***Potential*** Billing Determinants:

Monthly net control area load (energy) plus exports	Volumetric
Sum of the absolute value of maximum hourly SC deviations	Demand
Total of the absolute value of hourly SC deviations	Volumetric

Others?

Exh. No. ISO- 187, Page 6 of 11

3. MS: Market Infrastructure

- Conceptual Description:
  - The basic elements needed for markets for ISO to acquire balancing energy and ancillary services. This includes the minimum capabilities for the ISO to balance the system and ensure reliability on a routine basis, including minimum staffing, software and facilities necessary to operate a market, so that the ISO has balancing energy and A/S availability to do its job as a control area operator.
- ***Potential*** Billing Determinants:

Coincident demand, gross or net	Demand
Maximum **non-diversified,** noncoincident demand, gross or net	Demand
Maximum **diversified** non-coincident demand, gross or net	Demand

SC Maximum Demand for Market Services	Demand
Ratio of previous year market usage to total ISO market usage: Usage in MWh divided by total ISO Market MWh usage.	Demand

Others?

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4. MS: Market Usage

- Conceptual Description:
  - That portion of ISO market administration services/costs related more closely to usage levels. These market-related services would allow SCs to procure A/S and energy as desired, and would allow for more robust market activities according to the actions of market participants.
- ***Potential*** Billing Determinants:

Purchases & sales of energy & A/S	Volumetric
FTR MW (Note: if we decide to create a separate charge for FTR/CRR participation)	Demand

Others?

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5. CS: Customer Service

- Conceptual Description:
  - Services provided to market participants related to metering, billing, settlements, customer relations, training.
- ***Potential*** Billing Determinants:

Number of SCs	Customer
No of SC by size category based on transactions	Customer
No of SC by size category based on maximum demand	Customer

Others?

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Benefits

- Further unbundling (consistent with 2001 ID)
- Addresses concerns raised in litigation
- Addresses issue of matching cost drivers with cost recovery
  - Matches recovery of fixed costs with demand or customer charges.
  - May incorporate alternative rate designs advocated by participants, such as CPUC.

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Comments / Discussion

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	This data is subject always to the Disclaimer issued by the ISO at the time of its distribution.			
California ISO				
MD02 and ETCs				
Analysis Prepared for Discussion in the 2004 GMC Rate Structure Project				
MD02 Phase	**Application Name**	**ETC Impacts**	**What**	**Percent of System**
Phase 1A	AMP	No		
	RLC	No		
Phase 1B	Security Constrained Economic Dispatch (SCED)	Yes	Small, for real time, must get info from BITS since ETC and schedule after the Hour.	10%
	Settlements	Yes	Settlements currently must process ETC related information, and will do so in MD02.	10%
	SI - Workspace	Yes	Contract Reference Numbers	5%
Phase 2	Integrated Forward Market	Yes	Load Aggregation, Scheduling Priority	10%
	Market Transaction System (MTS)	Yes	Must be able to handle all information gathered in other systems.	20%
Phase 3	Locational Marginal Pricing (LMP)	Yes	Custom Load aggregation	10%
	Settlement Modifications	Yes	Settlements currently must process ETC related information, and will do so in MD02.	10%
	Transmission and Contract Optimization System (TaCOS)	Yes	This application exists primarily for ETC administration, but also has an OTC component.	90%
	Congestion Revenue Rights (CRR)	Yes	Load Aggregation, Scheduling Priority, allocation of CRR	40%
	Master File Redesign (MFRD)	Yes	Currently have ETC information in the Master File. At current time not sure if additional fields will be needed.	30%
Notes:				
The % estimates of the impact of ETC's on each system are rough approximations only, and are intended to represent the proportion of the total system necessary to accommodate ETC rights. Some of these estimates are based on specific additions that are required, but in general the ISO must maintain visibility for all ETC rights from bid to settlement to make sure that they are properly accounted for. Contracts for most of these MD02 elements have not yet been issued and the individual project costs will vary widely. As such, 90% of a smaller project could cost less than a very low percentage of a higher cost element.				
Some of the same requirements for ETC are also needed to accommodate Load Aggregation.				

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Disclaimer Regarding the Attached Data

The data is intended for the designated recipients only and is provided solely for the purpose of furthering discussion and research in the ISO's '2004 Rate Structure Project'. The data, in the form attached, is provided in response to Stakeholders' requests and as such does not necessarily indicate the ISO's concurrence in, or support for, its usefulness in developing a rate methodology. No implications may be drawn regarding the ISO's position on any subject in the Project from either the inclusion or exclusion of any specific data. The ISO does not warrant the completeness or accuracy of the data. The ISO is not necessarily the originator of the data.

Dated: February 14, 2003

INSTRUCTIONS

This data is subject always to the Disclaimer issued by the ISO at the time of its distribution.

SCENARIO BUILDING DIRECTIONS
STEP 1- Go to the "INPUTS" tab.
STEP 2- In the "Service Category Name and Billing Determinant" table, select the desired billing determinant for each category A through F (noting whether a demand or volumetric billing determinant is preferred).
STEP 3- (Optional step) Change the Service Category Name from "Category A", "Category C", etc. to whatever new name is desired .
STEP 4- In the "Service Category Percentage" table, choose the percentage of each cost grouping will be allocated to each Service Category (ensuring that the total going across for each cost group equals 100%).
STEP 5- Go to the "SUMMARY" tab.
STEP 6- (Optional step) Enter in the company's name who is proposing the new rate.

PURPOSE OF EACH TAB
SUMMARY TAB
This tab gives a snapshot view of the cost of each service category according to the percent allocation entered in the "INPUTS" tab. It displays the chosen billing determinants, their values and the units associated with each. It also calculates and displays the new rate, "Pro Forma Rate", by dividing each service category cost with its associated billing determinant.
INPUTS TAB
The purpose of this tab is for data entry depending on whatever billing determinant and cost grouping allocation scenario is desired.
CHANGES BY CUSTOMER CLASS
This tab is intended to give information on how each class total has changed from the old rate to the new rate scenario based on volumes.
FIXED & VOLUMETRIC COST %
This tab is intended to give the percentage breakdown of fixed versus volumetric costs for each cost grouping. The total dollar amount was used in calculating the cost of each service category (shown on the summary tab) based on the percent allocation entered in the "INPUTS" tab.

Proposal Summary

This data is subject always to the Disclaimer issued by the ISO at the time of its distribution.

PROPOSAL SUMMARY

Service Category Names	Cost	Billing Determinant			Pro Forma Rate
Category A	$4,950	Net Control Area Load plus exports	#########	MWh	$ 0.00
Category B	$3,300	Gross Control Area Load plus exports	#########	MWh	$ 0.00
Category C	$73,000	Gross Control Area Load plus exports	#########	MWh	$ 0.00
Category D	$121,725	Max Uninstructed Deviation	20,074	MW	$ 6.06
Category E	$49,000	Coincident Peak	45,977	MW	$ 1.07
Category F	$8,525	Max Uninstructed Deviation Energy	16,786,796	MWh	$ 0.00
Total	$260,500				

PROPOSED BY: Company X, Company Y, Company Z

DATE: 02/18/03

Inputs

This data is subject always to the Disclaimer issued by the ISO at the time of its distribution.

	Service Category Name and Billing Determinant		Type of Billing Determinant
A	Category A	Net Control Area Load plus exports	Volumetric
B	Category B	Gross Control Area Load plus exports	Volumetric
C	Category C	Gross Control Area Load plus exports	Volumetric
D	Category D	Max Uninstructed Deviation	Demand
E	Category E	Coincident Peak	Demand
F	Category F	Max Uninstructed Deviation Energy	Volumetric

		SERVICE CATEGORY PERCENTAGES						
	Cost Groupings	Category A	Category B	Category C	Category D	Category E	Category F	Total %
1	Real-Time Grid Operations	60%	40%					100%
2	Interchange Pre-Scheduling				100%			100%
3	Outage Coordination			50%	50%			100%
4	Operations Engineering, Maintenance and Support			100%				100%
5	Grid Planning				50%		50%	100%
6	Market Operations				100%			100%
7	Market monitoring and compliance			50%	50%			100%
8	Settlements, Billing, Credit Administration and Metering			100%				100%
9	Account Management Services and Training				50%	50%		100%
10	ISO contract administration					100%		100%
11	Administrative and General (allocated to others)					100%		100%
12	Startup Costs (allocated to others)			100%				100%
	Billing Determinant Denominator:	242,456,619	255,754,120	255,754,120	20,074	45,977	16,786,796	
	Units:	MWh	MWh	MWh	MW	MW	MWh	
		Volumetric	Volumetric	Volumetric	Demand	Demand	Volumetric	

Changes By Customer Class

This data is subject always to the Disclaimer issued by the ISO at the time of its distribution.
This part of the spreadsheet is still under development.

	New Rate						
	Category A	Category B	Category C	Category D	Category E	Category F	Total Class New Rate
IOU	2	-	14	151,593	-	-	$151,609
QF	2	0	-	303,186	21,315	10	$324,503
Muni/GE	-	1	21	181,912	-	-	$181,934
Other SCs	0	0	3	60,637	10,658	5	$71,298
Total Category New Rate	$4	$2	$39	$697,329	$31,973	$15	$729,345

		Old Rate			
		CAS	CONG	ASREC	Total Class Old Rate
1	IOU	50,000	-	4,500	$54,500
	QF	37,500	2,700	-	$40,200
2	Muni/GE	-	27,000	6,750	$33,750
3	Other SCs	5,000	2,700	900	$8,600
	Total Category Old Rate	$92,500	$32,400	$12,150	$137,050

	Difference
	Total Class Difference
IOU	$97,109
QF	$284,303
Muni/GE	$148,184
Other SCs	$62,698
Total Category Difference	$592,295

Breakdown of Cost Groupings by Percent Fixed and Volumetric Costs

This data is subject always to the Disclaimer issued by the ISO at the time of its distribution.

	Breakdown of Costs by % Fixed & Volumetric Costs			
	Cost Groupings	**Fixed**	**Volumetric**	**Total**
1	Real-Time Grid Operations	27%	73%	100%
2	Interchange Pre-Scheduling	23%	77%	100%
3	Outage Coordination	42%	58%	100%
4	Operations Engineering, Maintenance and Support	40%	60%	100%
5	Grid Planning	29%	71%	100%
6	Market Operations	18%	82%	100%
7	Market monitoring and compliance	40%	60%	100%
8	Settlements, Billing, Credit Administration and Metering	26%	74%	100%
9	Account Management Services and Training	6%	94%	100%
10	ISO contract administration	25%	75%	100%
11	Administrative and General (allocated to others)	0%	0%	0%
12	Startup Costs (allocated to others)	0%	0%	0%

Preliminary Grouping of Activities for ISO Rate Structure Version ~~12/19/200~~202/07/2003		
Grouping	**Activities within proposed Grouping**	**Indicative Cost Centers (there will be some overlap among cost centers)**
1. Real-Time Grid Operations	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 in near real time ~~Determination of resource adequacy~~ (same as above?) 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

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Originator: Ben Arikawa
Last updated: ~~12/19/200~~202/07/2003
"Note: Parties should clearly note that this grouping of activities and the assignment of cost centers may be altered as a result of the ongoing deliberations and developments in this process."

2. Interchange Pre-Scheduling	Day-ahead/Hour-ahead 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
3. Outage Coordination (other than real time)	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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4. 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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Originator: Ben Arikawa
Last updated: ~~12/19/2002~~02/07/2003
"Note: Parties should clearly note that this grouping of activities and the assignment of cost centers may be altered as a result of the ongoing deliberations and developments in this process."

5. Grid Planning	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

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6. Market Operations (A/S, RT & DA Energy, Transmission/Congestion)	Manage congestion (inter-zonal intra-zonal, LMP when implemented) Manage transmission and generation schedules: • Day and Hour-Ahead schedules (including Participating Intermittent Resources) • Day-Ahead market (under MD02) • Determine schedule feasibility 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
7. Marketing monitoring and compliance	Collect and analyze information on market behavior Develop new market rules or changes to market rules in response to market behavior Prepare and provide reports to regulatory authorities Perform oversight and investigations	1641 – Market Analysis 1642 – Market Surveillance Committee 1661 - Compliance 1662 – Data Quality Group

Exh. No. ISO- 190, Page 5 of 7

8. 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 Administration of RMR 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 1321 - Accounting 1331 – Treasury and Financial Planning

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9. 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
10. ISO contract administration	Administer ISO contracts (non-vendor, e.g., RMR, PTO, MSS) Negotiate, manage, litigate contracts	1731 – Contracts and Special Projects
11. 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
12. Startup costs	Recover costs associated with Startup	

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Preliminary Listing of Billing Determinant Data, Use and Source (~~12/17/2002~~02/14/2003 version)

	Data	Frequency	Period	Comments	Completed
1.	Gross control area load (energy) plus exports	Monthly	Calendar months, September 2001 – August 2002	Current billing determinant for Control Area Services.	Yes
2.	Net control area load (energy) plus exports	Monthly	see above	Not including behind the meter load of QFs and municipals	Yes
3.	Scheduled load plus exports	Monthly	see above	Use for scheduling charge if created	Yes
4.	Maximum coincident demand net	Monthly	see above	This is the sum of the maximum demand for each SC during the month coinciding with the ISO peak. For development of a demand charge	Yes
5.	Maximum non-coincident demand, net	Monthly	see above	This is the sum of the maximum demand for each SC during the month not coinciding with the ISO peak.For development of a demand charge	Yes

By: Ben Arikawa
Last updated: ~~12/17/2002~~ 02/14/2003

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6.	Maximum non-coincident absolute net uninstructed deviation (demand)	Monthly	see above	For each SC, this is the SC's maximum absolute net uninstructed deviation during any 10-minute interval The net uninstructed deviation is the absolute value of load deviations from schedules less generation deviations from schedules. Or alternatively, the difference between actual load and actual generation for an SC under the current system of balanced scheduling. For MID proposal	Yes
7.	Sum of absolute net uninstructed deviations (energy)	Hourly (or interval?)	see above	For each SC, this is the sum of the SC's absolute net uninstructed deviations during each of the 10-minute intervals in that month. For MID proposal	Yes
8.	Power withdrawals from the ISO-controlled grid (energy)	Monthly	see above	For each SC, this is the actual power that the SC withdraws from the ISO-controlled grid. This is actual metered load, not estimated gross load. Equivalent to net control area load plus exports.	Same as #2
9.	Sum of each SC's maximum purchases and sales of Ancillary Services, Supplemental Energy, and Imbalance Energy (both instructed and uninstructed). Not to include self provided AS	Monthly	see above	For development of demand charge for market operations. May be the same as 6 above.	Yes

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10.	Total purchases and sales of Ancillary Services, Supplemental Energy, and Imbalance Energy (both instructed and uninstructed). Not to include self provided AS	Monthly	see above	For development of energy charge for market real time activity (same as current billing determinant). Original GMC ASREO Bucket	Yes
11.	Number of SCs	Monthly	see above	For development of customer charge.	Yes
12.	FTR MW	Annual	see above	For development of FTR administration charge	Yes
13.	Number of transactions by SC, which would include scheduled loads, purchases/sales of ancillary services, supplemental energy, and imbalance energy, inquiries, etc. Note: this information would only be made available to stakeholders aggregated across all SCs. (No party made a specific request for this data.)	Monthly	see above	For use in developing a graduated customer charge if one is desired -- SCs can be grouped in to several groups depending upon their size (maximum demand and/or number of transactions). The information that would be given out would be aggregated up to categories—Category A includes xx SCs, Category B includes yyy SCs, etc. where we would define the parameters of the various categories. Need definition of transaction. No current request for this information.	Pending

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14.	Interzonal scheduled flows (HA)	Monthly	See above	Hour-Ahead scheduled flows across zones. Current billing determinant of interzonal congestion management (CONG) rate component.	Yes
15.	Real time transactions			PG&E may request this later.	Pending

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Preliminary Grouping of Activities for ISO Rate Structure Version ~~12/19/2002~~ 02/14/2003		
Grouping	**Activities within proposed Grouping**	**Indicative Cost Centers (there will be some overlap among cost centers)**
1. Real-Time Grid Operations	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 in real time 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 in real time Interchange scheduling in real time ETC scheduling and administration in real time EMS and Telemetry management System support for operational systems and interfaces (cc 1755)	1544 – Real Time Scheduling 1564 – Operations Scheduling-General (partial) 1546 – Security Coordination 1545 – Grid Operations 1566 – Regional Coordination 1461 – Control Systems 1755 – Business Solutions (partial)

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Originator: Ben Arikawa
Last updated: ~~12/19/200202~~/14/2003
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2. Interchange Pre-Scheduling	Day-ahead/Hour-ahead 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 **Analysis, design, software development and maintenance of computer applications related to the above (cc1755, cc 1481)**	1565 – Pre-scheduling and Support **1755 – Business Solutions (partial)** **1564 – Operations Scheduling-General (partial)** **1481– Markets and Scheduling (partial)**
3. Outage Coordination (other than real time)	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 **1564 – Operations Scheduling-General (partial)**

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4. 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

Exh. No. ISO- 192, Page 3 of 8

5. Grid Planning	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

6. Market Operations (A/S, RT & DA Energy, Transmission/Congestion)	Manage congestion (inter-zonal intra-zonal, LMP when implemented) Manage transmission and generation schedules: • Day and Hour-Ahead schedules (including Participating Intermittent Resources) • Day-Ahead market (under MD02) • Determine schedule feasibility 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 **Market development and Support** **Analysis, design, software development and maintenance of computer applications related to the above (cc 1481)**	1752 – Manager of Markets 1753 – Market Application and Testing 1757 – Market Integration 1756 – Market Quality **1755 – Business Solutions (partial)** **1481– Markets and Scheduling (partial)**

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Last updated: ~~12/19/2002~~02/14/2003
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7. Marketing monitoring and compliance	Collect and analyze information on market behavior Develop new market rules or changes to market rules in response to market behavior Prepare and provide reports to regulatory authorities Perform oversight and investigations **Potentially split this out:** **Operational compliance, compliance audits and compliance systems.** • **Operational compliance: monitors operational performance consistent with contractual and tariff commitments.** • **Compliance audits: monitors and corrects UFE and meter data timeliness and accuracy problems.** • **Compliance systems: applications related to compliance.**	1641 – Market Analysis 1642 – Market Surveillance Committee 1661 - Compliance 1662 – Data Quality Group **(Notes: currently these are in part charged to non-market categories. These are not)**

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8. 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 Administration of RMR 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 ~~1467 – Settlement System Services~~ 1321 – Accounting (partial) 1331 – Treasury and Financial Planning (partial)

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9. 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
10. ISO contract administration	Administer ISO contracts (non-vendor, e.g., RMR, PTO, MSS) Negotiate, manage, litigate contracts	1731 – Contracts and Special Projects
11. 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/overheads 1400 – Information Services indirects 1600 – Legal and Regulatory indirects 1700 – Market Services indirects 1800 – Corporate and Strategic Development indirects
12. Startup costs	Recover costs associated with Startup	

Notes for consideration:
RMR is spread through multiple groupings.

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Disclaimer Regarding the Attached Data

The data is intended for the designated recipients only and is provided solely for the purpose of furthering discussion and research in the ISO's '2004 Rate Structure Project'. The data, in the form attached, is provided in response to Stakeholders' requests and as such does not necessarily indicate the ISO's concurrence in, or support for, its usefulness in developing a rate methodology. No implications may be drawn regarding the ISO's position on any subject in the Project from either the inclusion or exclusion of any specific data. The ISO does not warrant the completeness or accuracy of the data. The ISO is not necessarily the originator of the data.

Dated: February 18, 2003

California ISO

			Market Participant Category					SC Categories				
								1	2	3		
										Other SC		
BAID	Acronym/SCID		SC	BA	PTO	SC	NMP	IOU	Muni - GE	Generator	Marketer/Broker	Comments
BUS_ASSOC_ID	SHORT_NAME	NAME	CAT.	TYPE								
4553	ALLG	Allegheny Energy Supply Company, LLC	MB	SIF		SC					1	
3001	AEP1	American Electric Power Service Corp		F							1	
2408	AEPS	American Electric Power Service Corporatior	MB	SIF		SC					1	
2149	AQPC	Aquila Power Corporation	MB	SIF		SC					1	
3371	AZCO	Arizona Electric Power Cooperative, Inc.	MB	SI		SC					1	
1011	APS1	Arizona Public Service Company-APS1	MB	SF		SC					1	
4976	APS4	Arizona Public Service Company-APS4	MB	S		MULT					1	
3751	APX3	Automated Power Exchange Inc-APX3	MB	S		MULT					1	Schedules ETCs
1020	APX1	Automated Power Exchange, Inc-APX1	MB	S		SC					1	Schedules ETCs
3992	APX4	Automated Power Exchange-APX4	MB	S		MULT					1	
4239	APX5	Automated Power Exchange-APX5	MB	S		MULT					1	
4774	APX6	Automated Power Exchange-APX6	MB	SI		MULT					1	
4833	APX7	Automated Power Exchange-APX7	MB	SI		MULT					1	
3451	AVA1	AVISTA CORPORATION		N			NMP				1	
1648	AEI1	Avista Energy Inc	MB	SIF		SC					1	
1227	BPA1	Bonneville Power Administration	MB	SIF		SC					1	
3112	PWRX	British Columbia Power Exchange	MB	SF		SC					1	
4793	PWR2	British Columbia Power Exchange - PWR2	MB	SI		MULT					1	
1528	BCHA	British Columbia Power Exchange Corporatic	MB	SIF		SC					1	
3951	CMWD	Calif. Department of Water Resources	MUNI/GE	S		MULT			1			
3652	CERS	California Department of Water Res.	MUNI/GE	S		MULT			1			
1088	CDWR	California Department of Water Resources	MUNI/GE	SF		SC			1			Schedules ETCs
1023	CAPP	California Polar Power Brokers LLC	MB	S		SC					1	
1247	PXC1	California Power Exchange		S		Inactive					1	
3335	PXC2	California Power Exchange 2		SI		Inactive					1	
3336	PXC3	California Power Exchange 3		S		Inactive					1	
3553	PXC4	California Power Exchange 4		S		Inactive					1	
3571	PXC5	California Power Exchange 5		S		Inactive					1	
3632	PXC6	California Power Exchange 6		S		Inactive					1	
3572	CALP	Calpine Energy Services	MB	SF		SC				1		
3211	CAL1	Cargill Alliant, LLC	MB	SIF		SC					1	
5056	CEPL	Citadel Energy Products LLC		F							1	
1168	CPS1	Citizens Power Sales	MB	SIF		SC					1	
1708	ANHM	City of Anaheim	MUNI/GE	SF		SC			1			Scheduled ETCs (not now)
5018	TO09	City of Anaheim - PTO		TU	PTO				1			
1868	AZUA	City of Azusa	MUNI/GE	SF		SC			1			Scheduled ETCs (not now)
4996	TO06	City of Azusa - PTO		TU	PTO				1			
1869	BAN1	City of Banning	MUNI/GE	SF		SC			1			Scheduled ETCs (not now)
5016	TO07	City of Banning - PTO		TU	PTO				1			
3431	BURB	City of Burbank, Public Service Department		N			NMP				1	
1628	GLEN	City of Glendale	MB	SI		SC					1	
1688	PASA	City of Pasadena	MUNI/GE	SU		SC			1			Schedules ETCs
1107	RVSD	City of Riverside	MUNI/GE	SF		SC			1			Schedules ETCs
5021	TO08	City of Riverside - PTO		TU	PTO				1			
1630	SNCL	City of Santa Clara, dba Silicon Valley Power	MUNI/GE	SI		SC			1			
1008	VERN	City of Vernon	MUNI/GE	SF		SC			1			Scheduled ETCs (not now)
5019	TO10	City of Vernon - PTO		TU	PTO				1			
3471	CRSP	Colorado River Storage Project		N			NMP		1			
3712	CONN	Conectiv Energy Supply, Inc.		N			NMP				1	
4956	CNCO	ConocoPhillips Company	MB	S		SC					1	
3251	CPSI	Constellation - DO NOT USE		SI		Inactive					1	
4894	HDPP	Constellation Power Source - HDPP	MB	SI		MULT					1	
3271	CPSC	Constellation Power Source Inc.	MB	SIF		SC					1	
2770	CRLP	Coral Power, LLC	MB	SF		SC					1	Schedules ETCs
1021	DETM	Duke Energy Trading and Marketing, L.L.C.	GEN	SF		SC				1		

California ISO

			Market Participant Category					SC Categories				
								1	2	3		
										Other SC		
BAID	Acronym/SCID		SC	BA	PTO	SC	NMP	IOU	Muni - GE	Generator	Marketer/Broker	Comments
BUS_ASSOC_ID	SHORT_NAME	NAME	CAT.	TYPE								
1024	ECH1	Dynegy Power Marketing, Inc.	GEN	SF		SC				1		Schedules ETCs
2509	EMMT	Edison Mission Marketing & Trading, Inc.	MB	S		SC					1	
1004	ESRC	Edison Source	MB	S		SC					1	
2590	EPE1	El Paso Electric Company		N			NMP				1	
4434	ELPM	El Paso Merchant Energy	MB	SI		MULT					1	
4513	ELPE	El Paso Merchant Energy - ELPE	MB	SI		MULT					1	
4256	EPME	El Paso Merchant Energy, L.P.	MB	SIF		MULT					1	
2289	EPPS	El Paso Power Services Company	MB	SI		SC					1	
2369	EESI	Enron Energy Services, Inc.		SIF		Inactive					1	
1005	EPMI	ENRON Power Marketing Inc	MB	SF		SC					1	
4494	ENRJ	ENRON POWER MARKETING, INC.	MB	SF		MULT					1	
3711	EWEB	Eugene Water and Electric Board		N			NMP				1	
4673	EXPT	Exelon Generation	MB	SF		SC					1	
1588	HFET	HAFSLUND ENERGY TRADING L.L.C.		S		Inactive					1	
4113	IDAC	IDACORP Energy, L.P.	MB	SF		MULT					1	
1668	IPC1	Idaho Power Company	MB	SF		SC					1	
1249	IEPI	Illinova Energy Partners, Inc		S		Inactive					1	
2999	KET3	Koch Energy Trading	MB	SIF		SC					1	
1189	LDWP	Los Angeles Water & Power		SI		Inactive			1			
1009	LGE1	Louisville Gas and Electric Company		S		Inactive					1	
2910	MEGA	Merchant Energy Group of the Americas, INC	MB	SIF		SC					1	
3611	MERL	Merrill Lynch Capital Services	MB	SIF		SC					1	
4813	MWSC	Midway Sunset Cogeneration Company	GEN	SI		SC				1		
2429	MIEC	Mieco, Inc.	MB	SI		SC					1	
1026	SCEM	Mirant	GEN	SF		MULT				1		
4654	MAEM	Mirant Inc.	GEN	SF		SC				1		
1308	MID1	Modesto Irrigation District	MUNI/GE	SF		SC			1			
2998	MSCG	Morgan Stanley Capital Group, Inc.	MB	SF		SC					1	
1750	NEVP	Nevada Power Company		N			NMP				1	
3011	NEI1	NewEnergy Inc.	MB	SF		SC					1	
1010	NCPA	Northern California Power Agency	MUNI/GE	S		SC			1			Schedules ETCs
3935	TO05	Pacific Gas & Electric Com		TU	MULT			1				
3931	PGAB	PACIFIC GAS & ELECTRIC COM.	IOU or MUNI/GE	SF		MULT			1			Schedules ETCs. Could be classified as IOU or Muni/GE.
3932	PCGB	PACIFIC GAS & ELECTRIC COMP	IOU or MUNI/GE	S		MULT			1			Schedules ETCs. Could be classified as IOU or Muni/GE.
5057	PCG2	Pacific Gas & Electric Company-PCG2	IOU or MUNI/GE	SF		MULT			1			Schedules ETCs. Could be classified as IOU or Muni/GE.
1187	TO01	Pacific Gas and Electric Co		TU	PTO			1				0
1015	PGAE	Pacific Gas and Electric Company	IOU	SF		SC		1				
3771	PCG1	Pacific Gas and Electric Company,	IOU	S		MULT		1				
1006	PAC1	PacificCorp	MB	S		SC					1	
3174	PCPM	PacifiCorp Power Marketing Inc.	MB	S		SC					1	
3573	PAC3	PacifiCorp-Green	MB	S		MULT					1	
2918	PECO	PECO Energy Company	MB	SIF		SC					1	
1017	PGES	PG & E Energy Services		SF		Inactive					1	
4032	PGET	PG&E Energy Trading	MB	SF		MULT					1	
2830	PETP	PG&E Energy Trading Power, L.P.	MB	SF		SC					1	
3933	COTB	PGAE & COTB	IOU or MUNI/GE	S		MULT			1			Schedules ETCs. Could be classified as IOU or Muni/GE.

California ISO

			Market Participant Category					SC Categories				
								1	2	3		
										Other SC		
BAID	Acronym/SCID		SC	BA	PTO	SC	NMP	IOU	Muni - GE	Generator	Marketer/Broker	Comments
BUS_ASSOC_ID	SHORT_NAME	NAME	CAT.	TYPE								
1147	COTP	PGAE & COTP	IOU or MUNI/GE	S		MULT			1			Schedules ETCs. Could be classified as IOU or Muni/GE.
1016	PORT	Portland General Electric Company	MB	SI		SC					1	
1067	PRM1	Power Resource Managers, L.L.C.	MB	SI		SC					1	
3191	PPLM	PP&L MONTANA, LLC		SI		Inactive					1	
3231	PSCO	Public Service Company of Colorado	MB	SIF		SC					1	
1448	PNM1	Public Service Company of New Mexico		N			NMP				1	
3391	GCPD	Public Utility District No. 2 of Grant County		N			NMP				1	
3131	PSE1	Puget Sound Energy	MB	SI		SC					1	
1068	NES1	Reliant Energy Services, Inc.	GEN	SF		SC				1		
4853	RWET	RWE Trading Americas Inc.	MB	SI		SC					1	
2995	SMUD	Sacramento Municipal Utility District		F			NMP		1			
1012	SRP1	Salt River Project	MB	SF		SC					1	
1188	TO02	San Diego Gas & Electric Co.		TU	PTO			1				
3511	SDG3	San Diego Gas & Electric, Merchant	IOU	SF		MULT		1				
1007	SDGE	San Diego Gas and Electric Company	IOU or MUNI/GE	SF		SC			1			Schedules ETCs. Could be classified as IOU or Muni/GE.
3811	SDG4	San Diego Gas and Electric, Merchant	IOU	S		MULT		1				
1029	SCL1	Seattle City Light	MB	S		SC					1	
3531	SEES	Sempra Energy Solutions	MB	SI		SC					1	
1022	SETC	Sempra Energy Trading Corporation	MB	SF		SC					1	
3333	SPPC	Sierra Pacific Power Company	MB	SI		SC					1	
4713	SCE5	Southern California Edison (5)	IOU or MUNI/GE	SI		MULT			1			Schedules ETCs. Could be classified as IOU or Muni/GE.
1268	SCE2	Southern California Edison Co	IOU or MUNI/GE	S		Mult			1			Schedules ETCs. Could be classified as IOU or Muni/GE.
1207	TO03	Southern California Edison Co.		TU	PTO			1				
1014	SCE1	Southern California Edison Company	IOU or MUNI/GE	SF		SC			1			Schedules ETCs. Could be classified as IOU or Muni/GE.
5076	SCE6	Southern California Edison-SCE6	IOU	S		MULT		1				
5077	SCE7	Southern California Edison-SCE7	IOU	S		MULT		1				
2997	SET1	Statoil Energy Trading Inc.		F							1	
4072	SEL2	Strategic Energy LLC	MB	SI		MULT					1	
2890	SEL1	Strategic Energy, LLC	MB	SI		SC					1	
1769	TCL1	Tacoma City Light		N			NMP				1	
4473	TEND	TenderLand Power Company		N			NMP				1	
4573	TEMU	TransAlta Energy Marketing (U.S.) Inc	MB	SIF		SC					1	
3392	TRAL	Transalta Energy Marketing Inc.	MB	SIF		SC					1	
3000	RNT3	Transmission Agency of Northern California		F					1			
1488	TEP1	Tucson Electric Power	MB	SI		SC					1	
3591	TID1	Turlock Irrigation District,		N			NMP		1			
4873	TXUE	TXU Energy Trading	MB	SI		SC					1	
4693	UBSW	UBS AG	MB	SI		SC					1	
3911	VSYN	VIASYN, INC	MB	S		SC					1	
1013	VGE1	Vitol Gas and Electric LLC		SI		Inactive					1	
1770	WALC	Western Area Lower Colorado		N			NMP		1			
4896	WCSL	Western Area Power Admin. - City of Shasta	MUNI/GE	S		MULT			1			
4897	WEPA	Western Area Power Admin.-Eastside Powe	MUNI/GE	S		MULT			1			
3952	WRDG	Western Area Power Admin.-Redding	MUNI/GE	S		MULT			1			
1127	WAMP	Western Area Power Administration	MUNI/GE	S		SC			1			

California ISO

			Market Participant Category					SC Categories				
								1	2	3		
										Other SC		
BAID	Acronym/SCID		SC	BA	PTO	SC	NMP	IOU	Muni - GE	Generator	Marketer/Broker	Comments
BUS_ASSOC_ID	SHORT_NAME	NAME	CAT.	TYPE								
4237	WDOE	Western Area Power Admin-WDOE	MUNI/GE	S		MULT			1			
5037	WEMT	Williams Energy Marketing & Trading-WEMT	GEN	S		SC					1	
1167	WESC	Williams Energy Marketing and Trading	GEN	SF		MULT				1		
		COUNT						10	37	8	94	

L E G E N D (for column E, "BA TYPE")

1	S	Scheduling Coordinator
2	T	Transmission Owner
3	G	Participating Generator
4	AP	Scheduling Coordinator Applicant
5	NPTO	Non-Participating Transmission Owner
6	O	Other
7		
8	F	Firm Transmission Rights Holder
9	R	Reliability Must Run Generation
10	N	Non-Market
11	A	Administration
12	SI	Inter SC Trade Only
13	SIF	Inter SC with FTR
14	SF	SC with FTR
15	SRA	Summer Reliability Agreement

NOTES:

1 Compilation of this list: List entities included in billing determinant data from 9/2001 to 8/2002 and append current SCs not included in that data.

2 For purposes of customer impact analysis in the 2004 GMC Rate Structure Project, the ISO will provide billing determinant data by customer class.
The analysis on this spreadsheet will be used to determine which SC identification codes will be included in each proposed customer class.
We will not split volumes from a single SC ID (except possibly for QF and Muni behind the meter load estimates that we included in existing billing determinant volumes.)
We have a standing proposal for 4 classes:

1. IOU
2. QF
3. Muni / Governmental Entity
4. Other Scheduling Coordinators

3 The "Comments" column notes which ID codes have had existing contract activity. Most of the IDs so identified are for MUNI/GE entities.
However, as IOUs schedule on behalf of some MUNI/GEs, we may wish to classify those codes as MUNI/GEs. This has been done in this proposed analysis.

4 As for the "COUNT" on line 159, this is not a count of Scheduling Coordinators, as some of these are multiple IDs used by a single scheduling coordinator, and some IDs are no longer active.

This data is subject always to the Disclaimer issued by the ISO at the time of its distribut

Scheduling coordinators were assigned to these classifications as indicated below:

Company	Grp	Desc
SCE (LADWP/Mojave)	n/a	
SDG&E (PV/APS/IID)	n/a	
CDWR	GE	Government Entity
PGAE & COTP	GE	
PG&E	GE	
SCE (Other Muni)	GE	
SDG&E (other Muni)	GE	
WAPA	GE	
Anaheim	GE	
APS (various)	GE	
Azuza	GE	
Banning	GE	
Cal PX (Tracy load)	GE	
Illinova (Bear Valley)	GE	
Pasadena	GE	
Riverside	GE	
Sempra (Vista load)	GE	
Vernon	GE	
American Elec Pwr	SC	Other Scheduling Coordinators
Aquila Power	SC	
Avista	SC	
Brit Columbia Pwr	SC	
BC Hydro	SC	
BPA	SC	
Calif Polar Pwr	SC	
Citizens Pwr Sales	SC	
City of Seattle	SC	
Coral Power LLC	SC	
Edison Mission Mktg	SC	
Edison Source	SC	
Idaho Power	SC	
LADWP	SC	
Mieco	SC	
Modesto	SC	

Montana Power	SC
NCPA	SC
PacificCorp	SC
Public Serv of NM	SC
Puget Sound Energy	SC
Portland General	SC
Sempra Energy Trdg	SC
Rounding & Other	SC
Arizona Public Svcs	SC
ENRON Power Mktg	SC
Illinova	SC
LG&E	SC
PG&E Energy Svcs	SC
Salt River Project	SC
Cal PX	SC
QFs	QF
APX	Mkt
Duke Energy Trdg	Mkt
Dynergy Power Mktg	Mkt
Reliant Energy	Mkt
South Co Energy Mktg	Mkt
Williams Energy Svcs	Mkt

Scheduling Coordinator
Qualified Facilities
Marketers

The distinction between Marketers and Other SCs is not meaningful. The ISO ha

1. IOUs
2. GEs
3. QF load
4. Other Scheduling Coordinators

ion.

:

is suggested that, based on a discussion between ISO staff and CPUC/EOB, staff Four classi

ifications could be of use:

MEMORANDUM

TO: Ben Arikawa

FROM: California Department of Water Resources State Water Project

SUBJECT: GMC – Preliminary listing of Customer Classes

DATE: February 13, 2003

The ISO's email and attachment of February 5, and memorandum of February 7, invite comments on the development of four classes of customers as follows: IOUs; Governmental entities/Municipal entities; QF volumes; and Other Scheduling Coordinators." The State Water Project of the California Department of Water Resources (SWP) has a number of questions and concerns regarding the efficacy of customer classification for the GMC.

OVERVIEW

The relevant factor for the GMC structure is not *who* is making use of the grid for which ISO costs must be recovered, but rather *how* participants are using the grid. During the GMC 2001 proceeding, the main point of contention, which was the basis for the Administrative Law Judge's directive to the ISO to do a study to refine "categories," was whether to charge for general grid management based upon gross load or net load. The salient question was not whether the affected customers were municipal entities or "QFs," but *how they used the grid.* Appropriately, the ISO now is proposing to craft a charge which reflects the differences in cost causation by the differences in *use*, not by category of *user.* The Federal Power Act embodies the premise that legal consequences may not turn on the nature of an entity or person, by requiring that tariffs not be unreasonably discriminatory. Categories based upon identity rather than on behavior, use, or function are inherently suspect, and must be justified as the best available approach consistent with non-discrimination principles.

Regulation by category of user has the related negative effect of putting entities into categories that do not fit with unpredictable and unreasonable consequences. For example, SWP has litigated the point that categorizing it as an "owner" for purposes of conversion would lead to the useless and financially disadvantageous exercises of developing a TRR and implementing a TRBA. Although these procedures make functional sense for a regulated transmission owner, it is a serious dislocation to apply such exercises to a customer, as the ISO apparently now recognizes. Similarly, SWP previously was told that, although it had the relevant electrical characteristics that would qualify it to receive the UFE treatment available to an MSS, it was not eligible, since that was intended for municipalities. However, the ISO also has reassessed its position on this matter in response to SWP's situation and characteristics. The underlying principle remains that regulation by category of user, rather than characteristics of use, is generally a dysfunctional approach conducive to unreasonable discrimination, and should only

be resorted to when the case is clearly made that it is the most accurate and practical way to measure use.

SPECIFIC COMMENTS

SWP offers the following specific comments and recommendations on the customer classifications.

First, there has been no explanation of the basis or guiding principles for designating the classes listed. It is difficult to comment meaningfully on categories for which the defining characteristics have not been provided. Other than the broad category titles, the elements of the members of each class are not stated. Without clearly discernible characteristics, there is no basis for establishing the four classes identified in the ISO's February 5 and February 7 communications.

Second, no cost-based reason or purpose has been put forth for developing customer classes. The four broad classifications listed have no obvious relationship to cost causation. With particular respect to the category labeled "Government Entities/Municipal Entities," whether an entity is a political subdivision of the State bears no obvious relationship to that customer's usage patterns or other characteristics as a customer of the ISO – its mode of operations, demand for services, and imposition of costs on the ISO. A government entity may be an electric system, or a regulatory agency, or a generator, or all of these, some of these, or none of these. In the case of SWP, the State Water Project is both a water system that purchases large amounts of electric power for system use, and a generator of electricity dedicated to system use. It is not an electric utility system *per se* like MID or Vernon, or an end-use only regulatory agency like CPUC.

Third, classification of customers according to only four or five or six broad classes is also fundamentally contrary to the GMC unbundling process. The ISO, FERC, and the participants have committed to *unbundling* cost functions, categories, services, and the GMC as a whole. Lumping numerous customers with very different usage patterns into a few broad categories was not anticipated and defeats the essential objective of granularity and cost identification which have been the focus of the efforts of the last five-plus years. In her Initial Decision in Docket No. EL00-313 (99 FERC ¶ 63,028 (2002), ALJ McCartney noted that "the ISO recognized that the unbundling of the GMC was a 'work in progress'....," and stated that "I agree with the parties that serious consideration of further unbundling of the GMC is appropriate." I.D. at 28, 36-37. As to service categories, the Judge further noted that "CPUC asserts that the only fix is further unbundling...." I.D. at 41. Similarly, the Offer of Settlement and Settlement Agreement (Article VI and Appendix B) approved by FERC on December 26, 2002 in the most recent GMC case (Docket No. ER01-250) (101 FERC ¶ 61,371 (2002) clearly reflects the objective of further unbundling.

Fourth, attempting to establish customer classes initially, before knowing the results of the ongoing refinement of cost items and their causation is like putting the cart before the horse.

If customer classifications are warranted, they should be developed *as the result* of the cost allocation process and further identification of cost causation, rather than being pre-selected at the outset and then potentially used later to "shoehorn" costs. Notably, the GMC process recognizes that billing categories, and cost classifications, can only be developed *after* detailed assessment of ISO costs and functions. Any development of customer classifications should follow a similar logical trajectory. Development of classes first, and cost assessment later, is inherently counter-intuitive.

Fifth, there has been no assessment of the impact of cost classification on the classes, or customers, or the process. Is the classification of customers into classes going to affect cost classifications, allocations, billing determinants, charge categories, and if so, how? How will a customer's bill, and usage patterns, be affected? Are such impacts desirable? Understanding such effects and impacts is essential in assessing the usefulness of customer classes.

Sixth, to the extent such customer classifications are adopted, it must be recognized that SWP, due to its unique operations, energy use, and purpose, does not fit into any of the categories considered so far. SWP is a wholesale customer with a very large single user load and its own generating facilities designed, built, and operated to serve that load in an efficient manner. It cannot be grouped together for rate purposes with other government/municipal entities with vastly different customer characteristics. Thus, while SWP does not believe that development of customer classes at this stage is productive, any list that might be developed must include a category which accurately reflects SWP's activities, modes of operations, usage patterns, and cost causation. ("End-user Gen"?)

In sum, SWP believes that the concept of customer classification presented so far suffers from several faults:

- The defining characteristics and guiding principles of the four classes have not been explained
- No cost-based reason or purpose for customer classification has been presented
- Customer classification in the manner proposed is a step backward towards re-bundling of the GMC
- Development of customer classes before refining the cost categories and identification of cost causation is not sequentially logical
- There has been no assessment of the impact of bundling customer classes on market efficiency or on affected customers
- SWP does not share usage characteristics with any of the four classes identified so far
- If customers are to be assigned to classifications, an additional class for large-load wholesale entities with their own dedicated-purpose generation facilities must be included to accommodate SWP.

Further time and resources should not be expended on developing customer classes in the GMC process when there is no obvious cost-related justification for it. The ISO and the parties need to focus on helping the ISO enhance its cost efficiency and run the ISO controlled grid and

market economically. As SWP stated in its previous comments of December 31, 2002 on the Preliminary Grouping of Activities, rate-responsive incentives for customers to adjust usage patterns can only be achieved if there is confidence that costs of usage-sensitive activities are assigned to billing categories which convey accurate price signals according to usage patterns. It is essential that costs not be assigned to charge categories, or customers assigned to classes, in a manner that would be counter-productive to unbundling by masking true cost causation. Such an action would result in unjustified cost shifts and raise serious questions as to whether the GMC would be just and reasonable.

As a general observation, it is unclear whether the concept of a system whereby ISO customers are assigned to various classifications at this stage is a "proposal" supported by the ISO, the CPUC, or others. If it is a proposal, it should be incumbent on the party advocating it to explain and provide a basis for it. To date, the ISO has not been able to provide SWP a reason for the classification, but has referred SWP to the CPUC. The CPUC in turn has indicated that it believes customer classes would provide a means of assessing the impacts on the classes (see Karen Shea's email of February 8), which does not answer the underlying question of why such an exercise should be undertaken in the GMC proceeding (one could as readily classify customers according to four different alphabetical listings or geographical locations and then assess the impacts on each group). If the ISO cannot provide a rate-setting justification for customer classes, it should not be proposing such a system. If it is not a proposal, further consideration of customer classifications appears to serve no useful purpose at this stage.

Disclaimer Regarding the Attached Data

The data is intended for the designated recipients only and is provided solely for the purpose of furthering discussion and research in the ISO's '2004 Rate Structure Project'. The data, in the form attached, is provided in response to Stakeholders' requests and as such does not necessarily indicate the ISO's concurrence in, or support for, its usefulness in developing a rate methodology. No implications may be drawn regarding the ISO's position on any subject in the Project from either the inclusion or exclusion of any specific data. The ISO does not warrant the completeness or accuracy of the data. The ISO is not necessarily the originator of the data.

Dated: February 14, 2003

Organization	2003 Adjusted Budget			
	BUD	INC	TOT	ACT
Grand Total				
1300 Chief Financial Officer				
1331 Financial Planning and Treasury				

Organization: 1331 Financial Planning and Treasury

Expense Type and Description	2003 Adjusted Budget			
	BUD	INC 1	TOT	ACT
Grand Total				
Salaries and Benefits				
110 Salaries - Regular				
112 Training Stipend				
113 Overtime / Call-out Bonuses				
114 Tuition Reimbursement				
115 Incentive / Spot Bonuses				
116 Relocation				
117 Housing Allowance				
118 Auto Allowance				
119 Other Compensation				
120 Working Holiday Allowance				
130 Salaries, including Burden				
131 Merit increases (budget only)				
132 Vacancy Factor				
133 Other Compensation Adjustments				
140 Employer Payroll Taxes				
Building, Lease and Facility				
210 Rents				
220 Facility Leases				
230 Equipment Leases				
240 Facility Operating Expenses				
Insurance and Interest				
310 Insurance Premiums				
350 Interest				
355 Interest				
358 Loan Charges				
Third Party Vendor Contracts				
410 IBM Contract				
415 MCI Contract				
420 Professional & Consulting Services				
440 Maintenance Contracts - Hardware				
445 Maintenance Contracts - Software				
640 Temporary / Contract Staff				
Professional and Consulting Services				
430 Consultants				
433 Consultant Expenses				
435 Recruitment Costs				
470 Other Contracts / Services				
480 Open				
490 Open				
495 Open				

Organization: 1331 Financial Planning and Treasury

Expense Type and Description	2003 Adjusted Budget			
	BUD	INC 1	TOT	ACT
Legal and Audit				
450 Legal Audit				
Training / Travel and Professional Dues				
510 Professional / Membership Dues				
520 Transportation and Travel				
530 Vehicle Costs				
540 Training Fees / Supplies				
550 Conference Fees				
560 Client Meetings				
570 Stakeholder Meetings				
580 Office Meetings				
Other				
0				
610 Office Supplies				
614 Software				
615 Office Equipment				
616 Hardware Equipment				
620 Publications / Subscriptions				
650 Advertising				
655 Printing Services				
660 Bank Fees				
665 Telephone				
666 Internet Services				
670 Postage / Courier				
680 Board Expenses				
681 Board Compensation				
690 Taxes				
691 Fines & Penalties				
696				
FERC Fees				
695 FERC Fees				
Contingency				
710 Contingency (Budget Only)				
810 Depreciation / Amortization				
820 Market Activity				
850 Unbudgeted / Non-cash				
940 Other Revenue				

Exh. No. ISO- 196, Page 1 of 2

Budget Allocation

Select Organization, Budget Period, Budget Program and Expense Code then click Refresh.
Please click the **Save** button below, after you make any changes. Otherwise your changes will be lost.

Organization: 1331 Financial Planning and Treasury

Budget Period: 2003 Adjusted Budget

Budget Program: Base Budget

Expense Code: 310 Insurance Premiums

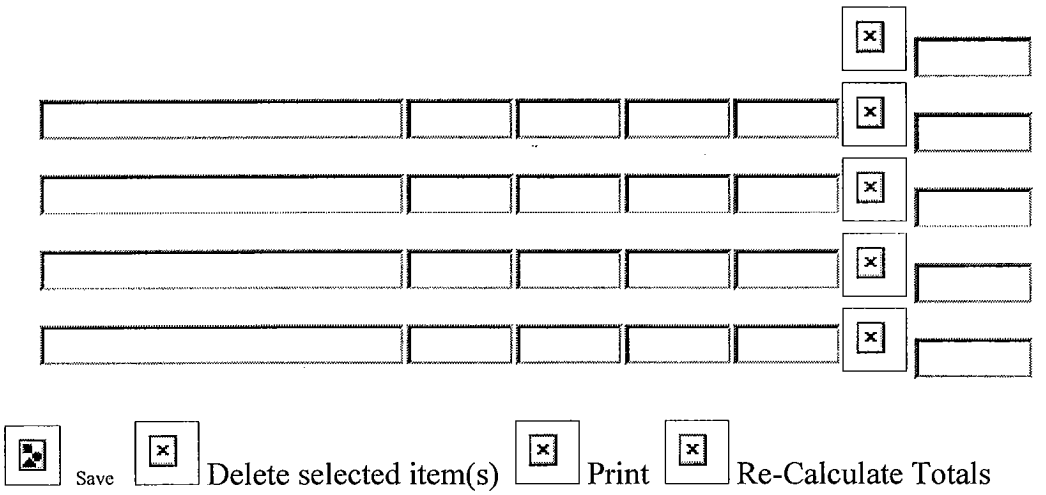
Refresh

Month **Task**

Save | Delete selected item(s) | Print | Re-Calculate Totals

	Description	CAS	CONG	MO	GEN	Total
	Auto	0%	0%	0%	0%	0%
	Commercial Liability	0%	0%	0%	0%	0%
	Crime (3 year program paid or	0%	00%	0%	0%	100%
	D&O Liability-Cost Increase of	0%	0%	0%	0	100%
	Directors & Officers	0%	0%	0%	0	100%
	Earthquake-Alhambra	0%	0%	0%	00	100%
	Excess/Professional Liability-C	0%	0%	0%	00%	100%
	Excess/Professional Liability/E	0%	0%	0%	0%	100%
	Excess/Professional Liability/E	0%	0%	0%	0%	100%
	Fiduciary	0%	0%	0%	0%	100%
	K&R	0%	0%	0%	0%	100%
	Property	0%	0%	0%	0%	100%
	Property Insurance (coverage	0%	0%	0%	0%	100%
	Storage Tank	0%	0%	0%	0	100%
	Workers Comp-Budget in payr	0%	0%	0%	0%	100%

Exh. No. ISO- 196, Page 2 of 2



 Save Delete selected item(s) Print Re-Calculate Totals

Budget Allocation

Select Organization, Budget Period, Budget Program and Expense Code then click Refresh.
Please click the **Save** button below, after you make any changes. Otherwise your changes will be lost.

Organization: 1331 Financial Planning and Treasury

Budget Period: 2003 Adjusted Budget

Budget Program: Base Budget

Expense Code: 110 Salaries - Regular

Refresh

	Base Salary
Budgeted	$0
Unbudgeted	$0
Total	$0

Staffing Detail **Task**

Save | Delete selected item(s) | Print | Re-Calculate Totals

Position and Name	CO	WH	ACR-OCL	OT	TS	Other
Director, Financial Planning-Treasurer: Leiber, Philip	0	0	0	0	0	
Sr Financial Analyst: Arikawa, Ben	0	0	0	0	0	
Manager, Financial Planning: Cogdill, Janice	0	0	0	0	0	
Contracts Technician: Coen, Cindy	0	0	0	0	0	
Financial Systems Analyst: Yoho, Edward	0	0	0	0	0	
Financial Analyst: Wright, Susan	0	0	0	0	0	
Administrative Assistant - 1331: Spencer, Christine	0	0	0	0	0	

Save | Delete selected item(s) | Print | Re-Calculate Totals

Budget Allocation

Select Organization, Budget Period, Budget Program and Expense Code then click Refresh.
Please click the **Save** button below, after you make any changes. Otherwise your changes will be lost.

Organization: 1331 Financial Planning and Treasury

Budget Period: 2003 Adjusted Budget

Budget Program: Base Budget

Expense Code: 110 Salaries - Regular

Refresh

Staffing Detail **Task**

Save | Delete selected item(s) | Print | Re-Calculate Totals

	Position and Name	CAS	CONG	MO	GEN	Total
	Director, Financial Planning-Treasurer: Leiber, Philip	0%	0%	0%	0%	0
	Sr Financial Analyst: Arikawa, Ben	0%	0%	0%	00%	0%
	Manager, Financial Planning: Cogdill, Janice	0%	0%	0%	0	0
	Contracts Technician: Coen, Cindy	0%	0%	0%	0	0
	Financial Systems Analyst: Yoho, Edward	0%	0%	0%	0	0
	Financial Analyst: Wright, Susan	0%	0%	0%	0	0
	Administrative Assistant - 1331: Spencer, Christine	0%	0%	0%	0%	0

Save | Delete selected item(s) | Print | Re-Calculate Totals

Exh. No. ISO- 199, Page 1 of 1

Budget Allocation

Select Organization, Budget Period, Budget Program and Expense Code then click Refresh.
Please click the **Save** button below, after you make any changes. Otherwise your changes will be lost.

Organization: 1331 Financial Planning and Treasury

Budget Period: 2003 Adjusted Budget

Budget Program: Base Budget

Expense Code: 660 Bank Fees

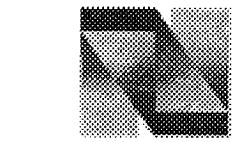
Refresh

Month **Task**

Save | Delete selected item(s) | Print | Re-Calculate Totals

	Description	CAS	CONG	MO	GEN	Total
☐	Bank Fees: 2002 Budgeted Le	0%	0%	0%	0%	100%
☐	Bank Fees: Based on 2002 ex	0%	0%	0%	0%	100%
☐	Bank Fees: Growth in # of acc	0%	0%	0%	0%	100%

Save | Delete selected item(s) | Print | Re-Calculate Totals



Navigant
CONSULTING, INC.

MEMORANDUM

DATE: February 10, 2003

TO: Ben Arikawa, Phil Leiber

FROM: David B. Cohen

SUBJECT: CAISO INDIRECT COSTS

Note: This document was prepared for the express purpose of starting a discussion and furthering the evaluation. Therefore, none of the contents may be regarded by the reader as any form of offer, undertaking, policy, proposal or commitment by the sender.

2004 GMC Rate Structure Project[1] -
a Stakeholder Process

The 2004 GMC Rate Structure Project is being performed in part to respond to the FERC Administrative Law Judge's 2001 GMC Initial Decision (ID) in ER01-313-000. In the ID the ALJ stated, "Rather, the entire GMC should be examined in totality and any restructuring or reallocations should be proposed and implemented in that overall context." [ID at page 50]. During the course of the hearing "The ISO agrees that there is always room for improvement, and the ISO is willing to entertain improvements in subsequent budget iterations. *Id.* 49:21-50:20".

A tool to assist the 2004 GMC Rate Structure Project is using the 2003 GMC Budget and Cost Allocation Matrix (CAM) for informational and discussion purposes. Examining the CAISO's 2003 Budget, reveals approximately $60 million out of $171.7 million of Operating Expenses (or 35 percent) are identified as Indirect Costs.

As part of a 2004 GMC Rate Structure Project there needs to be examination of all Cost Centers (Direct and Indirect) to determine if breakdown of previously identified Indirect costs can be achieved as part of the review that is being undertaken. The attached table identifies the Indirect Operating Costs in the 2003 CAISO Budget.
The CAISO Staff should have two working sessions in the latter part of February or early March 2003 to review all Indirect Cost Centers, with Stakeholders, to find out if further direct assignments to cost centers are reasonable.

Please advise all stakeholders of how the CAISO plans to address this issue.

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[1] Rate Structure includes: determination of services provided (current and future), accumulation of overall costs, cost allocation, rate design (including billing determinants). While not the primary focus of this group, the overall level of ISO costs (also referred to as the ISO revenue requirement) is of concern to ISO stakeholders, and consideration of a mechanism to adequately address this issue prospectively may be necessary.

ISO DEPT #	OPERATING COSTS	TOTAL COSTS
1500	Operations - Indirect Costs	
1511	VP Grid Operations - General	$1,011,957
1547	Engineering and Maintenance - General	$1,154,222
1548	OSAT	$267,932
1564	Operations Scheduling - General	$322,862
Total Operations Indirect Costs		$2,756,973
1700	Market Services - Indirect Costs	
1711	VP Market Services - General	$248,117
1721	Billing and Settlements-General	$353,911
1751	Market Operations - General	$959,968
Total Market Services Indirect Costs		$1,561,996
1400	VP Information Services Indirect Costs	
1411	Chief Information Officer- General	$212,246
	Corporate & Enterprise Applications -	
1422	General	$248,320
1466	Enterprise Applications	$816,499
1431	End User Support	$6,565,001
1432	Computer Operations - General	$430,975
1433	Network Operations	$1,629,905
1442	Production Support	$2,581,165
1451	Information Security	$1,509,500
1463	Operations Applications - General	$323,539
1471	IT Planning	$770,116
1468	Corporate Application Support	$1,333,287
1469	Analytical and Reporting	$1,055,106
1481	Markets and Scheduling	$1,520,628
Total IS Indirect Costs		$18,996,287

ISO DEPT #	OPERATING COSTS	TOTAL COST
1300	Finance - Corporate Indirect Costs	
1321	Accounting	$2,168,530
1331	Financial Planning and Treasury	$2,511,009
1351	Facilities	$5,812,962
1361	Office Administration	$2,227,171
Total Finance Indirect Costs		$12,719,672
1311	CFO - General	$424,204
1631	Legal and Regulatory	$13,118,010
1611	VP General Counsel - General	$385,985
1821	Communications	$865,811
1831	Strategic Development	$693,745
1851	Project Office	$657,758
1861	Regulatory Policy	$1,430,767
Total Corporate and Strategic Devpt b/f HR		$3,648,081
1811	VP Corporate and Strategic Development - General	$497,434
1100/1200	CEO / Human Resources - Corporate Indirects	
1111	CEO - General	$730,899
1841	Human Resources	$4,794,842
1651	Board of Governors	$163,100
Total CEO/HR Costs		$5,688,841
	TOTAL INDIRECT COSTS	**$59,797,483**

2004 GMC Rate Structure Project
List of documents provided under the Non-Disclosure Agreement

Item	Date	Parties receiving item
2003 Cost Allocation Matrix, modified for Modesto Irrigation District (MS Excel spreadsheet)	02/12/2003 (originally 01/16/2003)	MID, Navigant, NCPA, EOB
Budget allocation detail for cost centers 1424 and 1441	02/12/2003	MID, Navigant, NCPA, EOB
Capital Spending unbundling information from 2003 Budget	01/30/2003	MID (1/30/2003), Navigant, CDWR,
Uninstructed deviation data by SC (MS Access database)	01/27/2003	MID (1/30/2003), Navigant Consulting (1/30/2003), EOB (1/29/2003), CAC (1/29/2003), PG&E (1/29/2003)
2003 Cost Allocation Matrix (used in 2003 Budget)	01/16/2003	MID, EOB, CAC, PG&E
Board Budget Book (containing budget information sent to ISO Board)	01/16/2003	MID, EOB, CAC, PG&E

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2004 GMC RATE STRUCTURE PROJECT

California Independent System Operator Corporation

CALIFORNIA DEPARTMENT OF WATER RESOURCES STATE WATER PROJECT SUMMARY OF POSITION

February 19, 2003

SWP provides this interim summary of its position on activities and developments to date in the interest of advancing the restructuring process. SWP reserves its right to provide additional comments on various proposals of the parties, and to modify its position regarding any issue, as the GMC restructuring process continues.

COMMENTS ON DATA GATHERING AND ANALYSIS

SWP commends the ISO and the parties for the efforts and progress made to date. The separation of activities into twelve groupings represents a necessary and significant step toward increasing granularity in recognition of the various activities that the ISO performs. CDWR supports the recognition of Real-Time Grid Operations as a distinct grouping, as advanced by the ISO and reflected in SCE's Conceptual Proposal. This category should include all functions which allow the grid to operate reliably on a day-to-day and hour-to-hour basis, as distinguished from functions which ensure the long-term capability and reliability of the grid, which are more properly included under activity categories for Operations Engineering, Maintenance, and Support, and Grid Planning, which includes long-term transmission and generation resource planning.

As SWP noted previously in its December 31, 2002 Comments, clarification is needed concerning the activities termed as "Power flow studies and security analysis," and "Determination of resource adequacy," under the Real-Time Grid Ops grouping, to distinguish these functions from the long-term studies and analyses included in the Grid Planning grouping. The costs associated with conducting power flow studies and security analyses, and of resource adequacy determination, may be properly allocable to either Real-Time Grid Ops, or to Grid Planning, depending on whether the activity is for purposes of system operational planning, or system design and expansion.

SWP strongly supports the ISO's effort to identify Cost Centers by their relevant grouping or activity category(ies) as an important step forward in classifying costs according to causation. This will greatly assist market participants in understanding the correlation between the ISO's detailed activities identified in the CAM and the costs allocated to the various billing categories. Currently, for instance, some of the CAS functions enumerated in the Tariff, such as outage coordination, system or grid planning, transmission maintenance, correspond directly to a cost center, but most do not. As SWP has previously noted, there are 84 separate cost centers in the CAM, but only 15 activities identified in the Tariff (Tariff Sheet 308A), and it is not possible

to correlate the activities listed in the Tariff with the Cost Centers on the CAM. To further facilitate understanding, SWP proposes that the Cost Centers listed in the CAM include corresponding cross-references to the final categories identified in the Grouping of Activities.

With respect to Billing Determinant Data, SWP agrees that Gross Control Area Load plus exports data is essential. This is an appropriate basis for determining charges for the basic maintenance of the power system reliability, the costs of which all customers should share. It is still important to identify and reach consensus on which specific activities should be subject to assessment based on Gross Control Area Load. However, the ISO performs certain services with respect to all loads, and it is necessary to obtain data based on customers' total loads. Rate-responsive incentives for customers to adjust usage patterns can only be achieved if there is confidence that costs of usage-sensitive activities are assigned to billing categories which convey accurate price signals according to usage patterns, while only activities which are inherently insensitive to customer usage patterns are charged according to Gross Control Area Load. It is essential that costs not be assigned to the fixed-charge CAS category in a manner that would be counter-productive to unbundling by masking mask true cost causation.

CDWR also agrees that data based on the other categories listed in the December 16, 2002 version of the Billing Determinant Data is appropriate, with the exception of Maximum non-coincident demand. Non-coincident demand is not relevant for cost allocation or billing determinant purposes because the costs incurred by a transmission grid operator, including the ISO, depend on the maximum load which the grid must serve at any moment in time. Conversely, the individual maximum demands experienced by different entities on different days or time periods of the month are irrelevant because they do not bear any relationship to the ISO's actual costs.

PRELIMINARY COMMENTS ON OTHER PROPOSALS

SWP commends MID and SCE for their efforts in developing unique proposals. SWP believes that the three proposals under consideration – the ISO's, MID's, and SCE's – provide sufficient alternatives which cumulatively reflect the principal considerations for GMC structuring, and does not believe there is any need for SWP to develop a separate proposal at this time. T assist the process, SWP will provide comments and suggestions on the three proposals developed so far.

As discussed above, SWP strongly endorses the ISO's objective of assigning various functions to a Grouping of Activities. This list will form an essential basis for the ultimate development of billing or charge categories. SWP's specific comments on the ISO's Grouping of Activities and Billing Determinant Data have been provided in SWP's December 31, 2002 memo, and are further discussed above.

SCE's Conceptual Proposal, as a general matter, represents a significant refinement and improvement over the prior 3-category GMC. SCE's proposal provides greater granularity in the ISO's functions and resultant billing categories. SWP endorses the general concepts of a separate charge for Control Area Services, Scheduling, Market Operations, and Real-Time

Operations, as advocated by SCE. Specific comment will be provided as a more thorough understanding of SCE's proposal is given through the process.

MID's proposal provides a very useful perspective and assists in discussion and understanding of the ISO's activities. SWP remains concerned that MID's assessment that the ISO essentially performs only four overriding functions, condenses the ISO's activities in a way which overly homogenizes those functions and does not reflect the variety of functions, and associated cost incurrence, actually performed. In particular, the MID proposal does not sufficiently recognize the many activities associated with long-term transmission planning, design, maintenance, and growth, or the various immutable activities currently reflected in the CAS upon which *all* customers necessarily depend.

COMMENTS ON OTHER ITEMS RAISED DURING THE PROCESS

DWR's memorandum of February 13, 2003 expressed its objections to the separation of ISO customers into four classes. As stated therein, the relevant factor for the GMC structure is not *who* is making use of the grid for which ISO costs must be recovered, but rather *how* participants are using the grid. Categories based upon identity rather than on behavior, use, or function are inherently suspect, as they are inconsistent with basic principles prohibiting discrimination in rate making.

In particular, SWP has expressed a number of objections to customer classification in the context of the GMC. First, the defining characteristics and guiding principles of the four classes have not been explained. Second, no cost-based reason or purpose for customer classification has been presented. Third, customer classification in the manner proposed is a step backward towards re-bundling of the GMC. Fourth, development of customer classes before refining the cost categories and identification of cost causation is not sequentially logical. Fifth, there has been no assessment of the impact of bundling customer classes on market efficiency or on affected customers. Sixth, if customers are to be assigned to classifications, an additional class for large-load wholesale entities with their own dedicated-purpose generation facilities must be included to accommodate SWP.

Finally, SWP does not believe that consideration of ETC functions or alleged costs are appropriate for the GMC restructuring process, or than any further resources of the ISO should be expended in studying or analyzing ETCs. The costs of administering existing contracts were fully considered by both parties in the contract negotiation process and are reflected in the terms of the contracts, including the rate terms. As with any transmission contracts, the terms can only be changed by a renegotiation and/or a utility rate filing under section 205 of the Federal Power Act. For this reason, ETCs are not a proper subject for consideration the GMC restructuring process.

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California ISO
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Contact List for February 19, 2003 Meeting at PG&E Headquarters

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Web page posting ***(filenames in bold italics)***

Proposed Agenda - ***030219 proposed Agenda.doc***

Rate Proposals

SCE's Initial Conceptual Proposal for CAISO Rate Structure – already on page

Laurence Kirsch presentation on MID rate proposal - ***LDK_Modesto 030219.ppt***

California ISO Conceptual Rate Proposal - ***ISO Rate Structure Presentation 2-19-2003.ppt***

GMC Tool Prototype - ***GMC_hypo_tool_Rev1-distributed.xls***

Billing Determinant Data descriptions February 14, 2003 - ***Billing determinant data descriptions 030214.doc***

Preliminary groupings of activities - ***Proposed groupings of activities 030214 (revised).doc***

Customer Classes

Preliminary Mapping SC IDs to "Customer Classes" -- ***MP_Categorization_012703-distribution.xls***

CDWR comments of CAISO's Preliminary Mapping - ***DWR comments on customer classes (2-12-03).doc***

Budget Tool Template –

Budget Tool - ***budget tool template.xls***
Additional detail: insurance - ***insurance tasks Budget Allocation.htm***
Additional detail: Salary allocation - ***Salary Allocation.htm***
Additional detail: Salary Tasks - ***salary tasks Allocation.htm***
Additional detail: Bank Fees - ***Bank fees task Allocation.htm***

Assignment of Indirect Costs memo by David Cohen, Navigant Consulting - ***MEMO_INDIRECT COSTS.doc***

Data distributed (to date) under Non-Disclosure Agreement - ***Data distributed under NDA 030214.doc***

ETC Impact on MD02 Effort - ***03-02-12 MD02- ETC Info.xls***

California Independent
System Operator

2004 GMC Rate Structure Project
Notes from February 19, 2003 meeting

See attachments for agenda and list of attendees.

All documents discussed at the meeting are posted on:

http://www.caiso.com/docs/2003/02/07/2003020716402314262.html

A conference call to further discuss rate proposals and take up agenda items not taken up during the meeting was scheduled for Tuesday, March 4th at 10 AM. (Call in number 888-788-6681, passcode 921065)

The next in person meeting was scheduled for Monday, March 17th, 9:30 – 3:00 (PST) at the ISO in Folsom.

Presentation of Rate Proposals

The proponents of their respective proposals were given approximately 90 minutes each to discuss their proposals and to answer questions from other participants.

Some of the questions asked each proponent were similar in nature. These were (in no particular order):

- How would the rate structure treat the ISO's current congestion management costs? How would the costs of administering Locational Marginal Pricing be treated?
- When will the proposals be developed sufficiently so that overall cost assignments and rates can be determined? What steps are necessary for this to occur? What assistance does the proponent need from the ISO to complete their proposal?
- How would the proposal deal with "stranded costs?" Would these be explicitly addressed or would they be "rolled in" with other costs?

Southern California Edison's Rate Proposal

Bert Hansen gave a summary of Southern California Edison's rate proposal. As he was reviewing the proposal, the following issues were raised:

- Would this apply to entities other than SCE with Mohave? According to Bert, this would only apply to Mohave.

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- What would be the appropriate cost of this service? This would be determined in consultation with the ISO or through the use of the GMC Tool, which is under development.

- Treat DDES as a revenue credit – Instead of creating a separate rate component for DDES, why not bill directly and treat the revenue as a revenue credit that reduces the overall revenue requirement to be recovered through GMC rates?

- Would it be more productive for SCE and the CAISO to negotiate a cost rather than to spend time and effort on determining the cost? There appeared to be openness to discussions concerning this subject to a lack of objections from other participants.

- Why did Edison only consider energy charges? Edison argued that the ISO's responsibility was primarily to manage hourly transmission service and that implied only the use of energy charges. Even if the ISO had significant fixed costs, the use of energy only charges was justified.

- Why were the charges for Scheduling, Market Operations and Real-Time Operations services additive? Wouldn't this result in some inequities if an entity only procured in Real-Time vs. an entity that scheduled and procured Day-Ahead or Hour-Ahead? Edison was open to discussing the additive nature of the charges further.

- How would an entity that schedules Day-Ahead and then schedules Hour-Ahead changes be charged under this proposal? Edison stated that the absolute value of the schedule change would be added to the Day-Ahead MWh for the billing determinant.

- Into which service would the costs of the current interzonal congestion management service go? Would it not be "unfair" to make customers that generate (purchase) and consume within a zone to pay for the costs of interzonal congestion, so CONG costs should be kept separate? Edison stated that it is possible to have pre and post-MD02 rate structures if stakeholders prefer this.

- (A question to the ISO from David Cohen) Will CONG be used in when LMP is implemented? Will the software that is currently used to perform interzonal congestion management continue to be used when Locational Marginal Pricing is implemented? If this software (and other software) is no longer being used, is it worthwhile to consider separating out these capital costs from other capital costs.

Modesto Irrigation District Rate Proposal

Dr. Laurence Kirsch presented the Modesto Irrigation District's rate proposal. The following were some of the major questions asked during his presentation:

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- Are settlements, billing and metering costs assigned to the Managing Transmission Flows function? Dr. Kirsch stated that the current MID proposal did not assign these costs to the Managing Transmission Flows function.

- Would Metered SubSystems bear any metering costs? Dr. Kirsch offered that the MID proposal did not make any special arrangements for MSSs. MSSs would pay the ISO's costs of participating in markets and for resolving energy imbalances.

- Could a third party actually perform the Administering Markets function? It is possible for a third party to perform this function.

- Would flows under Existing Transmission Contract Rights be assessed the Managing Transmission Flows charge? Dr. Kirsch said that he is not knowledgeable about ETCs and how they affect the GMC applicable to ETC holders. In principle, the Managing Transmission Flows charge should apply to all net control area flows (plus exports); but he did not know whether this principle could legally be applied to ETCs.

- There was a discussion of the ability of the ISO to charge for incremental scheduling changes. This issue was brought up because MID was uncertain if it would argue for the creation of a fourth function, Scheduling Generation, Load and Transmission Facilities.

- In reference to this potential fourth function, had MID attempted to quantify the costs of incremental schedule changes? No. Because incremental costs were likely to be small, MID had not pressed the issue so far.

- (Question to the ISO) Does the ISO keep track of schedule changes? Yes, the ISO does.

- (Question to the ISO) Didn't the ISO reject assessing a charge on transactions? No, the difficulty was in defining a transaction. If it is clearly defined, then the ISO might consider a transactions charge.

- (Question to ISO) Wouldn't more recent data give a better picture of billing determinants for 2004? This was in response to a discussion about the volatile nature of some billing determinants. The ISO would, to the extent new final settlement information is available and cleared by counsel for distribution, provide updated billing information.

- What is the billing determinant for the Resolving Energy Imbalances function? Dr. Kirsch stated that uninstructed deviations is the billing determinant.

- Had MID done an analysis of the rate impacts of their proposal? No, but cost causation should determine the proper rate structure, not rate impacts.

- Is MID proposing a two-part rate for each function? No, MID proposes a demand and energy charge for Resolving Energy Imbalances only. The Managing Transmission

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Flows function costs would be recovered through a charge on net control area flows. The Administering Markets function costs could be recovered using whatever billing determinants that the ISO is using or considering. The costs of Scheduling Generation, Load and Transmission Facilities would be recovered through an assessment on schedule changes.

- Has MID thought about the issue of "stranded costs?" Not explicitly. MID considers that their proposal allows the ISO to recover all of its costs, "stranded" or otherwise.

California Independent System Operator Conceptual Rate Proposal

Phil Leiber gave the presentation on the CAISO' conceptual rate proposal. The following is a synopsis of the questions and comments during this presentation:

- Will the ISO allow participants to work with the ISO on the assignment of costs to the different functions?

- What are maximum diversified demand and maximum non-diversified demand? Maximum diversified demand is the sum of the demands of a given set of customers at a specific time. Coincident demand (sum of demands at system peak) of all QFs is a diversified demand. Non-diversified demand is the sum of the maximum demands of a given set of customers regardless of the time that they occurred.

- Will the ISO consider comments on how the diversified demand concept? Can the ISO develop a forecast of diversified demand and keep track of it? A diversification factor can be developed and applied on a going forward basis.

- Customers do not like paying going forward for something that they did 12 months ago. The ISO needs to consider application of this on a prospective basis and inform customers of the change.

- Are categories 1 (Core Reliability Services), 3 (Market Infrastructure) and 5 (Customer Service) for recovery of fixed costs and 2 (Energy and Transmission Services) and 4 (Market Services) for recovery of variable costs? ~~Not necessarily. Both methods could be applied to some of the latter. [To Ben from Laurence: I heard Phil say that 5 is a mixture, but that 1 and 3 are basically (but not entirely) fixed cost categories while 2 and 4 are basically (but not entirely) variable cost categories.]~~Categories 1 and 3 are mostly fixed, while 2 and 4 are mostly variable. Category 5 is a mixture.

- Reliability Services includes some congestion management costs. Where do the rest of congestion management costs get assigned? Not certain at this time as the ISO has not yet had the time to do the assignment.

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- (Question to MID) How does the Core Reliability Services function match up with the Managing Transmission Flows function? Dr Kirsch stated that the CRS was a mixture of Managing Transmission Flows and Resolving Energy Imbalances.

- Is the ISO seriously considering net control area load as a billing determinant on Energy and Transmission Services? Has this been discussed with ISO officers? Yes, the ISO is considering assessing net control area load the ETS charge. Yes, the officers were given a presentation similar to the one given today.

- What is volumetric? Volumetric means assessed on a per MWh basis. Demand is assessed on a per MW basis.

- LMP will not be implemented until later in 2004. There is no separate charge for congestion management. The current ISO proposal appears to "double charge" imbalances and not congestion. There needs to be a charge for the use of congested paths. This led to a discussion of congestion management under the current zonal system vs. that under a nodal system.

- There needs to be consideration of California's current regulatory framework in which utilities self-schedule and imbalances are small.

- Does the ISO have a sense of the magnitude of the costs of the CRS function? Has the ISO had discussions with other ISOs or compared CRS to other control area functions in the WECC? No, we have not completed the cost assignment. The ISO also has not had discussions on this with other ISOs. Other ISOs may not be valid comparisons.

- Are categories 1 (CRS) and 3 (Market Infrastructure) similar in that they are fixed? Will they have similar billing determinants? No, they do not necessarily contain only fixed costs and may not have similar billing determinants.

- What's the difference between stock trades and energy trades that requires a fixed charge? The ISO is required to perform certain functions and needs to maintain an infrastructure. The ISO has fixed costs just to stand ready to meet the need, just like an Utility Distribution Company does.

- It seems to me that fixed costs should be recovered through a customer charge component. Then the ISO has to recover its revenue requirement. It needs to do the cost assignment first, then design rates. Don' have circular reasoning. Don't move costs if you determine that costs are too high.

- Don't reinvent the wheel with MD02; find economies of scale and get ISO costs down.

- What is the distinction between 3 (Market Infrastructure) and 4 (Market Services)? Market Infrastructure are primarily fixed costs and Market Services are primarily variable costs.

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- Why wouldn't settlements and billing be partially based on volume? Could be.

- Would the ISO consider breaking out fees for training, investigations, etc., into a separate component? The ISO is not considering a separate "fee" component. FERC staff does not like having fees fund investigations. Furthermore, these fees would not be significant enough to warrant a separate component.

- What has the ISO done with fines? There was a discussion of the ISO's use of fines.

- Has the ISO done anything to reduce its costs with reductions in market volumes? The Vice President of Market Services has looked into this with his staff. One-third of Market Services costs are under his control. One-third are overheads and one-third are capital costs. Some of the first one-third could be reduced, but most are not volume related.

- ISO market volumes have increased and 55 percent of these volumes are for inter-SC trades.

- Do these inter-SC trades get assessed charges? No, the load that receives the energy is assessed the GMC.

- On a cost-causation basis, if you are providing a service, you should charge for it. How does the inter-SC trade work? There was a discussion of inter-SC trades.

- Why not charge for inter-SC trades within the customer charge? An SC could be allowed a fixed number of trades under the charge and be assessed for additional trades. (Response from MID) MID proposed this charge during the 2001 GMC proceeding and FERC "squashed" it. There was a discussion of what MID proposed and what FERC staff had actually stated.

CDWR discussion of Customer Classes

CDWR had submitted a memorandum to the ISO on February 13, 2003 raising its concerns with a proposal to develop customer classes to determine bill impact analysis. The discussion centered around the CPUC's request that the ISO develop customer classes so that the impacts of any new rate structure could be seen. CDWR objected to an arbitrary classification of customers prior to the development of fully fleshed out rate designs. The ISO does not recognize customer classes per se, but is indifferent to their use if participants can agree on a mapping of SC IDs to customer classes on their own. CDWR and the CPUC will have discussions to see if they can reach agreement on a classification method. David Cohen, Navigant Consulting, reserved judgment on the mappings pending further examination.

GMC Tool

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There was a brief presentation on the "GMC Tool" requested by the David Cohen. This tool is a spreadsheet that, once completed, will contain a mapping of cost center costs to groupings of activities and can be used to develop rate proposals. The ISO will continue to work on this Tool and asked for comments.

Budget Tool

There was a brief overview of the ISO's Budget Tool in which ISO directors and managers develop and justify their budgets. Screen shots are available on the 2004 GMC Rate Structure Project main page.

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RE GMC - ISO Webpage - confidential documents 02-21-03.txt
From: Arikawa, Ben
Sent: Friday, February 21, 2003 8:30 AM
To: Neal, Sean
Cc: Morrison, Stephen
Subject: RE: GMC - ISO Webpage - confidential documents

Sean,

The lack of a place for documents on the public and confidential GMC discussion boards was an oversight on our part. We are discussing wit h
the Webmaster about getting this functionality onto those boards soon.

I'vyou have any □uestions, please do not hesitate to contact me. on under the NDA and the parties to whom we have sent these documents. I f
you would like a copy of any of them, just let me know. I believe tha t
MID has been sent all of the documents and data on the list.

Note: the attached documents are circulated by the sender solely for the express purpose of informing discussion. Therefore, none of the contents may be regarded by the reader as any form of offer, undertaking, policy, proposal or commitment by the sender, author or the California ISO.

Ben Arikawa
Senior Financial Analyst
California Independent System Operator
151 Blue Ravine Road
Folsom, CA 95630

Voice: (916) 608-5958
fax: (916) 351-2259

email: barikawa@caiso.com

-----Original Message-----
From: Morrison, Stephen
Sent: Thursday, February 20, 2003 4:31 PM
To: Neal, Sean
Cc: Arikawa, Ben; Springer, John
Subject: RE: GMC - ISO Webpage

Sean,

RE GMC - ISO Webpage - confidential documents 02-21-03.txt

There are no documents on the password protected part of the site so far. I also understand that it is not yet up and running and fully functioning. As soon as that happens we will send out the passwords to the ND certificate holders. If there are any Confidential Materials you need copies of, please drop Ben a line.

Thanks.

Stephen

Stephen A S Morrison

Corporate Counsel

California ISO

(916) 608 7143

The foregoing e-mail communication (together with any attachments thereto) is intended for the designated recipient(s) only. Its terms are confidential and may be protected by the attorney/client, or other applicable, privilege. Unauthorized use, dissemination, distribution, or reproduction of this message is strictly prohibited.

-----Original Message-----
From: Sean Neal [mailto:SMN@dwgp.com]
Sent: Thursday, February 20, 2003 12:56 PM
To: SMorrison@caiso.com
Subject: GMC - ISO Webpage

RE GMC - ISO Webpage - confidential documents 02-21-03.txt

Stephen:

I was wondering if you had a password to the confidential section of the GMC Stakeholder section of the ISO's webpage. I am guessing that what's on it is the confidential data that Ben said was sent to Laurence Kirsch, Jan Pritchard, Ross Hemphill, etc. But if the ISO's password protected part is up and running, I'd like to take a look.

Thank you,

Sean

RE GMC - ISO Webpage - confidential documents 02-21-03a.txt
From: Sean Neal [SMN@dwgp.com]
Sent: Friday, February 21, 2003 10:30 AM
To: BArikawa@caiso.com
Cc: SMorrison@caiso.com
Subject: RE: GMC - ISO Webpage - confidential documents

Ben, Stephen:

Thank you. I think I'm good for now on those files, but thanks for following up.

Sean

>>> "Arikawa, Ben" <BArikawa@caiso.com> 02/21/03 11:30AM >>>

Sean,

The lack of a place for documents on the public and confidential GMC discussion boards was an oversight on our part. We are discussing wit h
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I've attached a list of the documents and data that we have provided under the NDA and the parties to whom we have sent these documents. I f
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MID has been sent all of the documents and data on the list.

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Thank you,

Sean

California Independent
System Operator

Proposed Agenda for Conference Call
2004 GMC Stakeholder Process
March 4, 2003
10:00 a.m. to 12:00 p.m.
Conference Call-in #1-888-788-6681
Passcode: 921065

Introductions/Announcements
Follow-up discussion of rate proposals
Assistance required by proponents
Clean-up issues from February 19th meeting (Discussion of indirect assignments, public discussion page, preparation for next meeting)

By **Bert Hansen** on **Friday, February 21, 2003 - 02:51 pm**:

The Conceptual GMC proposal that Southern California Edison submitted for consideration in the 2004 GMC stakeholder process has billing determinants that are all energy based (all five services that SCE has proposed are billed on a per MWh basis). SCE was asked at the February 19 Stakeholder meeting to provide an explanation why SCE supports energy billing determinants (BDs), and does not support other BDs for the ISOs GMC, such as demand charges or customer charges.

SCE's response at the meeting is that our support for energy BDs is that they are consistent with the basic nature of the service that the ISO provides, which is hourly transmission service. I am submitting this note to elaborate on that comment.

The GMC, together with the transmission access charge (TAC) and wheeling charges, represent the price that customers of the ISO (scheduling coordinators) pay for ISO transmission service. Admittedly, the GMC is of a lesser magnitude than the Access Charges, but still comprises a significant portion of the overall price of transmission service from the perspective of a scheduling coordinator. High Voltage Wheeling Access charges currently are $1.58 per MWh for PG&E wholly-owned exit points, $2.39 per MWh for SCE exit points, and $2.27 per MWh for SDG&E exit points. The current Control Area Services rate is $0.569 per MWh. If the total GMC were expressed on a bundled per MWH basis, the rate would be $0.98 per MWh. So the GMC costs are a significant portion of the price of ISO transmission service.

It is important that the rates for ISO transmission service be designed such that they do not interfere in the efficient operation of ISO markets, and also so that they are fair to customers. Since GMC rates represent somewhere around a third of the total cost of ISO transmission service, GMC rates are an important element of total ISO transmission service rate design.

A little more background: The ISO's customers are scheduling coordinators (SCs). Scheduling coordinators come and go, and from time to time represent different loads and different generators. This was particularly true when there were no restrictions on direct access, such that retail end-use customers could switch Electricity Service Providers (ESPs) as often as they desired. A customer could switch ESPs anytime (say in the middle of a month), meaning that the SC representing that customer also switched mid-month. Or, an ESP could switch its SC mid-month, meaning that there would be a large shift in load from one SC to another SC on that particular day.

Today there are limits on the ability of customers to switch ESPs, but no limits on the ability of ESPs to switch SCs. This means that it is still true today that the loads of particular retail end-use customers may be represented by one scheduling coordinator one day, and another the next day. Furthermore, the ISO is still designed around the concept of being able to support full customer choice and direct access, even if some restrictions are in place at this time.

We should not adopt a GMC rate design that interferes with that basic design of the ISO, to be able to accommodate customer choice and direct access. SCE believes that energy-based BDs are most able to accommodate the basic ISO design. This is because with energy BDs, it does not matter which SC represents a customer on a particular day, since each MWh will be billed to whatever SC that represents that load on that day. Total ISO GMC revenue billed on a per MWh basis does not vary depending on which SC represents which retail customers. Furthermore, the bills to each SC are "fair" from the perspective that when an

SC's represented load increases or decreases, its GMC bill correspondingly increases or decreases.

With demand charges, it does matter which SC represents a load on a particular day. A shift of retail customers from one SC to another SC will affect total ISO revenue. For example, a shift in load from a large SC to a small SC that occurs after the peak load of the month will not lower the large SC's demand billing determinant, but in general will increase the small SC's demand BD. It is also not fair from the perspective of the SCs. The small SC will pay an entire month's charge even though it represented a load for part of a month.

Theoretically, the ISO could institute demand charges that varied as a function of how many "customers" a scheduling coordinator had in an attempt to eliminate the negative aspects of demand charges mentioned above. However, any such effort would be very complicated, and require tracking of additional statistics. Additionally, if "demand" is defined as a function of other BDs, then a demand charge is not really a demand charge in any case. So SCE does not see that it is practical to attempt to rectify the shortcomings of demand charges in this manner.

Additionally, wheeling out of the ISO grid, such as for exports to other utilities surrounding the ISO, is often sporadic in nature. A SC may not wheel out at all for some time, followed by a short period of wheeling out. Demand charges are not well suited to this kind of service, since it is discretionary. In SCE's opinion, the current energy-based billing determinants for wheeling charges of the ISO are best for wheeling. Since the GMC is a component of the price of wheeling, this is further support for assessing the GMC on energy-based billing determinants also.

To summarize, SCE's support for energy based billing determinants for the ISO's GMC is based on the concept that the GMC rate design should be compatible with the nature of the service provided by the ISO, and consistent with the basic design of the ISO. Energy based billing determinants accomplish this, and demand charges do not.

CHRISTENSEN ASSOCIATES

Laurits R. Christensen Associates, Inc.
4610 University Avenue, Suite 700
Madison, Wisconsin 53705-2164

Voice 608.231.2266 Fax 608.231.2108

TO: Ben Arikawa

FROM: Ross Hemphill & Laurence Kirsch

DATE: 3/3/03

SUBJECT: Rate Design of The California ISO's Grid Management Charge

Attached please find our tentative proposal for designing the GMC.

Although we believe that the analysis does not disclose confidential material, it does rely on data that are confidential under the Non-Disclosure Agreement. Consequently, the proposal's header indicates that its distribution is "Limited to Those Who Have Signed the Non-Disclosure Agreement." This limitation may be lifted if and when the ISO and other parties find that wider distribution would not compromise confidentiality.

ANALYSIS BASED ON CONFIDENTIAL INFORMATION
REVIEW LIMITED TO THOSE WHO HAVE SIGNED THE NON-DISCLOSURE AGREEMENT

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 flesh out details of the rate design proposal made by Dr. Kirsch in the California ISO's 2002 Grid Management Charge proceeding.[1] These details include numbers to the extent that we have numbers at this time.

In the spirit of trying to find common ground with the tentative positions expressed by the ISO in its recent presentation entitled *ISO Conceptual Rate Structure*[2], the rate design proposal that we make in this paper reflects two major principles:

- The customers who use the ISO's services should pay for those services to the extent practical.
- Unavoidable fixed costs should be recovered through fixed charges (i.e., demand and customer charges) to an extent consistent with economic efficiency.

To simultaneously adhere to these two principles, we functionalize costs according to the services the ISO provides to customers; and we classify the costs to billing determinants within functions according to the proportions identified by the ISO as fixed or variable. These costs are then allocated by the appropriate billing determinants to derive the rate design. Section 1 discusses functionalization while Section 2 addresses allocation.

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]

---

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

[2] Phil Leiber, *ISO Conceptual Rate Structure*, 2004 GMC Rate Structure Project Meeting, San Francisco, February 19, 2003.

[3] The engineering literature repeatedly states that system operators aim to minimize some set of system 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;

- *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, in principle, two of these other services merit 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.
- *Scheduling generators, loads, and transmission facilities* so that SCs can set and update their schedules.

Nonetheless, we note that, in the 2002 Grid Management Charge proceeding, FERC Staff raised questions concerning whether separate scheduling charges were consistent with FERC policy.[4] Because of these questions and because we expect that the dollars related to the scheduling function are relatively small, we will not advocate a separate scheduling function in the 2004 GMC rate proceeding, though we may be receptive to the arguments of any parties who might advocate charges for this function.[5]

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.

[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] We note that any such charges should reflect, to the extent practicable, the incremental capital and variable costs that the ISO incurs to provide scheduling.

1.2. Cost Assignments for Our Proposed Functions

To facilitate the assignment of costs to our proposed functions, the ISO provided to us 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. After making our cost assignments for these 63 "direct assignment" departments, the spreadsheet automatically assigned the costs of "indirect assignment" departments to our functions. The spreadsheet, which is attached, shows that the ISO's costs are assigned to our functions as follows:

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%

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.

2. CLASSIFYING COSTS AND DESIGNING RATES [6]

In this section, for each of the three functions, we discuss classification of costs as energy, demand, or customer related; and the identification of appropriate billing determinants for designing the rates for each ISO service.

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 imbalance function need to be simple and familiar to customers. Hence, we propose that, in each month,

[6] Unless otherwise indicated, Billing determinant data are from the ISO spreadsheet entitled "Aggregated data for distribution.xls."

the billing determinants be an energy measure, a demand measure, and a customer measure. For each SC in each month, the proposed billing determinants are as follows:

- *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.[7]
- *The customer measure* is the number of SCs.

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.[8]

TABLE 2
BILLING DETERMINANTS
FOR THE RESOLVING ENERGY IMBALANCES FUNCTION

Billing Determinant	Quantity	Data Period
Uninstructed deviation energy	16,786,796 MW-intervals	9/01-8/02
Uninstructed deviation demand (most recent 12 months)[9]	54,276 MW	9/01-6/02
Number of SCs	73 SCs	9/01-6/02

Because we do not have sufficient information to determine how the costs of this function should be classified among the energy, demand, and customer charges, and because the ISO has not yet apportioned costs among its categories, we cannot make a definite rate proposal at this time. In principle, the costs that would be customer-related and classified according to the number of SCs would be those that vary with the number of SCs. Subject to examination of the ISO's methods

[7] Because of the long-term instability of imbalance volumes, a period longer than 12 months may be appropriate for the demand billing determinant.

[8] 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 trend in the data that are available to us.

[9] The interval-by-interval dataset of uninstructed deviations show that, for the period September 2001 through June 2002: a) the maximum absolute deviation for each SC *over the 10-month period*, summed over SCs, is 4,523 MW; and b) the maximum absolute sum of the deviations of the SCs *in any one interval* is 584 MW. "Aggregated data for distribution.xls," sheet "Max Uninstructed Dev demand," shows that the maximum absolute deviation for each SC *in each month*, summed over SCs, ranges between 1,228 MW and 2,213 MW. The substantial (and unsurprising) diversity of imbalances among SCs yields this effect of the billing determinants summing to substantially larger figures over larger periods of time. Because we are proposing the billing determinant be the highest value over the most recent 12-months, the 10-month figure is the one that is most relevant to our proposal. Over the course of a year, this figure is equivalent to 54,276 MW-months (equals 12 months times 4,523 MW).

and results, we might be satisfied to classify the remaining costs between the demand and energy billing determinants in proportion to how the ISO apportions costs between the "Core Reliability Services" and "Energy and Transmission Services" categories that it described in its *ISO Conceptual Rate Structure* presentation. This is consistent with the notion that the first category is mostly fixed costs that are recovered through a demand charge while the second is mostly variable costs that are recovered through a volumetric charge.

Pending information on the ISO's cost apportionment, we present, in Table 3, the rates that would occur if 5% of Resolving Energy Imbalances costs were classified as customer-related and if the remainder were equally classified to the energy and demand charges.[10]

TABLE 3
RATES FOR THE RESOLVING ENERGY IMBALANCES FUNCTION

Billing Determinant	Cost	Quantity	Rate
Uninstructed deviation energy	$20,155,788	16,786,796 MW-intervals	$1.20 / MW-interval
Uninstructed deviation demand (most recent 12 months)	$20,155,788	54,276 MW	$371.36 / MW-month
Number of SCs	$ 2,121,622	73 SCs	$2,422 / customer-month

The level of the charges in Table 3 reflects the level of the ISO's energy balancing costs. We note that 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 an 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.

Although we find the case for a demand charge less compelling for the Managing Transmission Flows function than for the Resolving Energy Imbalances function, we recognize that this is a service that only the ISO can provide, and that it incurs substantial fixed costs to be able to provide it. Hence, we propose that, in each month the billing determinants for this function include an energy measure, a demand measure, and a customer measure. For each SC in each month, the proposed billing determinants are as follows:

[10] 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 energy measure* is the sum of the SC's power withdrawals from the ISO-controlled grid.
- *The demand measure* is the SC's maximum power withdrawal from the ISO-controlled grid during the current month and the preceding eleven months.
- *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.

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
Maximum power withdrawals[11]	625,912 MW-months	9/01-8/02
Number of SCs	73 SCs	9/01-6/02

The costs that would be classified according to the number of SCs would be those that vary with the number of SCs. Subject to examination of the ISO's methods and results, we might once again be satisfied to classify the remaining costs between the demand and energy billing determinants in proportion to how the ISO apportions costs between the "Core Reliability Services" and "Energy and Transmission Services" categories that it described in its *ISO Conceptual Rate Structure* presentation. Again, this is consistent with the notion that the first category is mostly fixed costs that are recovered through a demand charge while the second is mostly variable costs that are recovered through a volumetric charge.

Again pending information on the ISO's cost apportionment, we present, in Table 5, the rates that would occur if 5% of Managing Transmission Flows costs were classified as customer-related and if the remainder were equally classified to the energy and demand charges.

[11] For the 12-month period September 2001 through August 2002, "Aggregated data for distribution.xls" shows that net system energy is 242,457 GWh, gross system energy is 255,754, and the highest non-coincident peak for gross loads in any month is 55,020 MW. In Table 4, 625,912 MW-months = 12 months * 55,020 MW * 242,457 GWh / 255,754 GWh. Note that, because diversity of customers' loads may cause SCs' annual non-coincident peaks to fall in different months, the 625,912 MW-months figure is likely to be low relative to the actual, so that the required rate is likely to be lower than the $97.36 / MW-month figure shown in Table 5.

TABLE 5
RATES FOR THE MANAGING TRANSMISSION FLOWS FUNCTION

Billing Determinant	Cost	Quantity	Rate
Power withdrawals	$60,940,789	242,456,619 MWh	$0.25 / MWh
Maximum power withdrawals	$60,940,789	625,912 MW-months	$97.36 / MW-month
Number of SCs	$ 6,414,820	73 SCs	$7,323 / customer-month

2.3. Administering Markets

The costs of administering markets should be recovered from the customers who trade in these markets. Measurement of the customers' use of the markets should be according to some combination of the volumes (MWhs) and values (dollars) traded. The measurement should probably differ by the service traded (e.g., energy, spinning reserves, financial transmission rights), though such differences might be captured sufficiently by measures of value 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.

Competition undermines the rationale and practicality of demand and customer charges for two reasons. First, it means 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, the 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 because the customer has nowhere else to go.

Hence, we propose that, in each month the billing determinant for this function be as follows:

- *Trading volumes*, which can be measured as a combination of MWhs traded and dollars traded, and which may differ by the service (e.g., energy, spinning reserves) traded.

Table 6 shows the billing determinants and the values that we use for purposes of calculating rates. In the table, trading volumes are measured solely by the aggregate MWhs traded, with a MWh of energy given exactly the same weight as (for example) a MW-h of spinning reserves. Although the experience of competitive commodity markets leads us to believe that

consideration of dollar values and differentiation among services are warranted, we use the aggregate MWhs figure for the immediate purpose of this proposal.

TABLE 6
BILLING DETERMINANTS
FOR THE ADMINISTERING MARKETS FUNCTION

Billing Determinant	Quantity	Data Period
Trading volumes	73,374,094 MWh	9/01-8/02

Table 7 shows the consequent rates.

TABLE 7
RATES FOR THE ADMINISTERING MARKETS FUNCTION

Billing Determinant	Cost	Quantity	Rate
Trading volumes	$66,870,735	73,374,094 MWh	$0.91 / MWh

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 is reconciled through an adjustment to the following year's revenue requirement.

2004 GMC Stakeholder Process
March 4, 2003
10:00 a.m. to 12:00 p.m.
List of conference call participants

	Last Name	First	Company	Telephone	E-mail Address
1	Arikawa	Ben	ISO	(916) 608-5958	barikawa@caiso.com
2	Cohen	David	Navigant Consulting	(503) 708-7852	dcohen@navigantconsulting.com
3	Hansen	Bert	SCE	(626) 302-3649	berton.hansen@sce.com
4	Hemphill	Ross	Christensen Associates	(608) 321-2266	rchemphill@lrca.com
5	Kirsch	Laurence	Christensen Associates	(415) 663-8608	lkirsch@lrca.com
6	Kissel	Peter	CDWR		
7	Leiber	Phil	ISO	(916) 351-2168	pleiber@caiso.com
8	LeVine	Debi	ISO	(916) 351-2144	dlevine@caiso.com
9	Lyon	Deane	ISO	(916) 351-2428	dlyon@caiso.com
10	McGuffin	Mike	ISO	(916) 608-5753	mmcguffin@caiso.com
11	Mi	JingChao	CDWR	(916) 653-1095	jmi@water.ca.gov
12	Morrison	Stephen	ISO	(916) 608-7143	smorrison@caiso.com
13	Peterson	Mike	ISO	(916) 608-5896	mpeterson@caiso.com
14	Pritchard	Jan	MID	(209) 526-7490	janp@mid.org
15	Schoenbeck	Don	CAC/EPUC		dws@keywaycorp.com
16	Springer	John	ISO		jspringer@caiso.com
17	Terry	Lee	CDWR	(916) 653-4657	lterry@water.ca.gov
18	Timson	David	ISO		dtimson@caiso.com
19	Withrow	David	ISO	(916) 608-7134	dwithrow@caiso.com
20	Wolfe	Lisa	EOB	(916) 322-8613	lwolfe@eob.ca.gov
21	Yap	Catherine	Barkovich and Yap		

California ISO
2004 GMC Rate Structure Project
Contact List for March 4, 2003 Conference Call

	Last Name	First	Company	Telephone	E-mail Address	Present
1	Arikawa	Ben	ISO	(916) 608-5958	barikawa@caiso.com	x
2	Cohen	David	Navigant Consulting	(503) 708-7852	dcohen@navigantconsulting.com	x
3	Hansen	Bert	SCE	(626) 302-3649	berton.hansen@sce.com	x
4	Hemphill	Ross	Christensen Associates	(608) 321-2266	rchemphill@lrca.com	x
5	Kirsch	Laurence	Christensen Associates	(415) 663-8608	lkirsch@lrca.com	x
6	Kissel	Peter	CDWR			x
7	Leiber	Phil	ISO	(916) 351-2168	pleiber@caiso.com	x
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9	Lyon	Deane	ISO	(916) 351-2428	dlyon@caiso.com	x
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13	Peterson	Mike	ISO	(916) 608-5896	mpeterson@caiso.com	x
14	Pritchard	Jan	MID	(209) 526-7490	janp@mid.org	x
15	Schoenbeck	Don	CAC/EPUC		dws@keywaycorp.com	x
16	Springer	John	ISO		jspringer@caiso.com	x
17	Terry	Lee	CDWR	(916) 654-3327	lterry@water.ca.gov	x
18	Timson	David	ISO		dtimson@caiso.com	x
19	Withrow	David	ISO	(916) 608-7134	dwithrow@caiso.com	x
20	Wolfe	Lisa	EOB	(916) 322-8613	lwolfe@eob.ca.gov	x
21	Yap	Catherine	Barkovich and Yap			x
22	Alessandri	Patrick	EOB	(916) 322-8672	palessandri@eob.ca.gov	
23	Aoki	Rod	CAC	(415) 421-4143	rsa@a-klaw.com	
24	Barkovich	Barbara	Barkovich and Yap			
25	Bracht	Kirk	CPUC	(415) 703-2868	kwb@caiso.com	
26	Brommer	Mike	TID	(209) 883-8320	mtbrommer@tid.org	
27	Epstein	Mike	ISO	(916) 351-2314	mepstein@caiso.com	

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California ISO
2004 GMC Rate Structure Project
Contact List for March 4, 2003 Conference Call

	Last Name	First	Company	Telephone	E-mail Address	Present
28	Franklin	Brett	EOB	(916) 322-8587	bfranklin@eob.ca.gov	
29	Hoffman	Kyle	ISO	(916) 608-7057	khoffman@caiso.com	
30	Kaplan	Katie	IEP	(916) 448-9499	kaplan@iepa.com	
31	Kehrein	Carolyn	EMS	(707) 678-9506	cmkehrein@ems-ca.com	
32	Koo	Tony	PG&E	(415) 973-0520	txkb@pge.com	
33	Lam	Tony	EOB	(916) 322-8632	tlam@eob.ca.gov	
34	Lengenfelder	David	FERC	(916) 294-0175	david.lengenfelder@ferc.gov	
35	Lucero	Ed	Sempra	(858) 654-1781	elucero@semprautilities.com	
36	Metz	Dan	PG&E	(415) 973-4742	dkm2@pge.com	
37	Neal	Sean	MID			
38	Olsson	Ray	EOB	(916) 322-8628	rolsson@eob.ca.gov	
39	Regan	William	ISO	(916) 351-4450	wregan@caiso.com	
40	Ross	James	CAC	(626) 530-9544	jimross@r-c-s-inc.com	
41	Ryan	Mike	WAPA	(916) 353-4434	mryan@wapa.gov	
42	Schneider	Susan	Phoenix	(916) 797-3106	schneider@rsvl.net	
43	Shea	Karen	CPUC	(415) 703-5404	kms@cpuc.ca.gov	
44	Takehara	James	NCPA	(916) 781-4293	james.takehara@ncpa.com	
45	Tran	Nguyet	PG&E	(415) 973-2024	ntt1@pge.com	
46	Wade	Kathy	PG&E	(415) 973-4401	kawa@pge.com	
47	Walz	Edna	CDWR	(916) 324-1720	ewalz@doj.ca.gov	
48	Yakin	Dale	PG&E	(415) 973-1752	dgy4@pge.com	

Exh. No. ISO- 212, Page 2 of 2

California Independent
System Operator

2004 GMC Rate Structure Project
Notes from March 4, 2003 conference call

Agenda

Introductions/Announcements
Follow-up discussion of rate proposals
Assistance required by proponents
Clean-up issues from February 19th meeting (Discussion of indirect assignments, public discussion page, preparation for next meeting)

All documents discussed at the meeting will be posted on the 2004 GMC Rate Structure Project main page (once the issue of confidentiality is addressed):

http://www.caiso.com/docs/2003/02/07/2003020716402314262.html

The next in person meeting was scheduled for Monday, March 17th, 9:30 – 3:00 (PST) at the ISO in Folsom.

The conference call started at about 10:05 with a roll call. Twenty-one participants were on for part or all of the call. The list of participants can be found at the end of these notes.

Presentation of Rate Proposals

After roll was taken, it was determined that Southern California Edison was not on the call. Modesto Irrigation District (MID) was asked to discuss its progress on its rate proposal. At the beginning of this discussion, the ISO pointed out that there was a possibility of confidentiality issues concerning the text document, "Rate Design Of The California ISO's Grid Management Charge," written by Laurence D. Kirsch and Ross C. Hemphill of Christensen Associates. The issue over confidentiality stems from the use of confidential data in the development of cost assignments and billing determinants. The authors had placed the disclaimer, "Analysis Based On Confidential Information, Review Limited To Those Who Have Signed The Non-Disclosure Agreement," on the document. There did not appear to be confidential information contained in the document as there were no identifiable Scheduling Coordinators (SCs), no data attributable to any SC, and no disaggregated confidential cost information. (Later during the conference call, Stephen Morrison, ISO counsel, stated that he would look confer with ISO staff before determining determine document's status.)

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After this discussion, Dr. Kirsch proceeded to explain the method that MID followed in developing their rate proposal. As Dr. Kirsch explained it, MID was following standard utility ratemaking practice by developing functions, assigning costs to functions and then classifying costs to fixed and variable components within each function. MID's three functions are Resolving Energy Imbalances, Managing Transmission Flows and Administering Markets.

Dr. Kirsch explained that MID would wait for the ISO to determine the classification of fixed vs. variable costs before finalizing its own proposal. To develop its proposal for the call, MID assumed that 5 percent of Resolving Energy Imbalances and Managing Transmission Flows costs were customer related, 47.5 percent were demand related and 47.5 percent were energy related. MID had considered a fixed cost component to the Administering Markets function, but rejected that because they did not find it plausible justification for assessing a demand or customer charge.

There was a discussion of billing determinants starting with the use of net deviations by interval. David Cohen asked if MID had verified the aggregated data using the disaggregated data. MID had not, but would now that Cohen brought it up.

CDWR brought up the question of the use of non-coincident peak as a billing determinant for the demand component of the Managing Transmission Flows function. This discussion centered on whether the ISO's costs were driven by system peak (coincident) or by non-coincident peak.

Dr. Kirsch proceeded to discuss MID's rationale for the volumetric billing of the Administering Markets charge. He pointed out that he would have preferred to differentiate market volumes by trades and MWh. There was a discussion of the relative volumes of AS capacity and MWh volumes in the market.

Dr. Kirsch stated that based on these conversations, MID would revise its results in a few days. At this point, the question of confidentiality was brought up again. (See opening paragraph of these notes.)

There was a discussion of the true-up mechanisms if costs or revenues were higher or lower than forecast. MID had assumed an annual true-up without the necessity of making a rate filing. Some parties argued that a Section 205 filing at the FERC should be required in the event of over or undercollection. Dr. Kirsch was unaware of the controversy that the quarterly adjustment had caused during the 2002 GMC Settlement discussions.

The ISO was next to discuss its proposal. Phil Leiber ISO stated that their proposal had changed with the addition of a Scheduling Service and the folding of the Market Infrastructure charge into the Market Services component. Phil began discussing the ISO's preferred billing determinants. For the Core Reliability Services function, it was gross non-coincident demand, possibly diversified, though it was not decided yet. The preferred billing determinant for Energy and Transmission Services was net control area load plus exports with the potential for using a second billing unit of net deviations to recover some portion of the costs. The preferred billing

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determinants for Scheduling Services are the number of final HA schedules submitted and MWh volumes under each schedule. The billing determinant for Market Services is the same as the ASREO billing determinant, purchases and sales of AS capacity and real time energy. A demand charge was possible also. Customer Services would be billed on a per customer (SC) basis with some scaling factor to account for larger customers.

MID pointed out that, based on past experience, there did not seem to be a volumetric dimension to scheduling, just a fixed cost basis. CDWR mentioned that the separation of scheduling services had some merit and wanted to know the magnitude of costs in this component. The ISO did not have data at this time, but is working on costs for all the components.

Again there was a discussion of the relative merits of non-coincident demand and coincident demand as a "good" billing determinant.

The ISO mentioned that it most likely would not have a "fully fleshed out" proposal ready for the meeting on March 17th. There was some discussion about canceling the in-person meeting and having a conference call instead.

SCE was last to discuss its proposal. SCE did not have costs associated with its functions yet. They would be working on this. The ISO asked if SCE had all the data that it required or if it needed additional assistance from the ISO. SCE stated that it thought it had the necessary information, but would contact the ISO if additional data were needed.

The ISO asked if SCE had contacted other parties to see if there were interest in David Cohen suggestion that SCE negotiate with the ISO concerning the Dynamic Dispatch Export Service rather than pursue this in a separate rate design. SCE had not, but was open to look at this.

CDWR asked about the status of the customer class issue. The ISO had nothing to report as it had requested that the CPUC finalize the assignment of customer classes, but did not have a response yet. The EOB, as it was working jointly with the CPUC, was asked if it had any information concerning this. It did not, but would contact the CPUC to check on the status.

Finally, there was a discussion of scheduling the next and future meetings. David Cohen requested that the ISO consider scheduling meeting far in advance to block out times on participants schedules. We anticipate at least two meetings in April with the possibility of a conference call on March 17th.

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2004 GMC Stakeholder Process
March 4, 2003
10:00 a.m. to 12:00 p.m.
List of conference call participants

	Last Name	First	Company	Telephone	E-mail Address
1	Arikawa	Ben	ISO	(916) 608-5958	barikawa@caiso.com
2	Cohen	David	Navigant Consulting	(503) 708-7852	dcohen@navigantconsulting.com
3	Hansen	Bert	SCE	(626) 302-3649	berton.hansen@sce.com
4	Hemphill	Ross	Christensen Associates	(608) 321-2266	rchemphill@lrca.com
5	Kirsch	Laurence	Christensen Associates	(415) 663-8608	lkirsch@lrca.com
6	Kissel	Peter	CDWR		
7	Leiber	Phil	ISO	(916) 351-2168	pleiber@caiso.com
8	LeVine	Debi	ISO	(916) 351-2144	dlevine@caiso.com
9	Lyon	Deane	ISO	(916) 351-2428	dlyon@caiso.com
10	McGuffin	Mike	ISO	(916) 608-5753	mmcguffin@caiso.com
11	Mi	JingChao	CDWR	(916) 653-1095	jmi@water.ca.gov
12	Morrison	Stephen	ISO	(916) 608-7143	smorrison@caiso.com
13	Peterson	Mike	ISO	(916) 608-5896	mpeterson@caiso.com
14	Pritchard	Jan	MID	(209) 526-7490	janp@mid.org
15	Schoenbeck	Don	CAC/EPUC		dws@keywaycorp.com
16	Springer	John	ISO		jspringer@caiso.com
17	Terry	Lee	CDWR	(916) 653-4657	lterry@water.ca.gov
18	Timson	David	ISO		dtimson@caiso.com
19	Withrow	David	ISO	(916) 608-7134	dwithrow@caiso.com
20	Wolfe	Lisa	EOB	(916) 322-8613	lwolfe@eob.ca.gov
21	Yap	Catherine	Barkovich and Yap		

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2004 GMC Rate Structure Project Briefing

To: Participants in 2004 GMC Rate Structure Project

From: Ben T. Arikawa, Senior Financial Analyst

Date: March 7, 2003

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

This Briefing contains:

- Draft meeting notes for the March 4, 2003 conference call;
- A listing of confidential documents available under the Non-Disclosure Agreement
- A suggested change to the March 17, 2003 in-person meeting to a conference call
- A link to California Department of Water Resources – State Water Project ***Summary of Position*** that was distributed at the end of the February 19, 2003 meeting; and,
- Distribution of updated aggregated billing determinant data.

Draft meeting notes for March 4, 2003 conference call

Attached to the e-mail transmitting this Briefing are draft meeting notes. Please review them and provide edits or comments back to me by close of business, March 13th. Once finalized, they will be redistributed.

Listing of confidential documents available

Also attached to the e-mail transmitting this Briefing is a list of confidential documents that are available and the parties to which these documents have been sent. Please review the list for accuracy. In checking my files, I found some inaccuracies in the list that was previously distributed on February 18th just prior to the last in-person GMC meeting.

If you would like a copy of any document on the list, please let me know. Your organization must have signed the Confidentiality Agreement and you must have signed the Non-Disclosure Certificate in order for you to receive any of the documents.

March 17, 2003 meeting

At this time, the ISO intends to hold a conference call instead of an in-person meeting on March 17, 2003 unless another participant intends to present a conceptual proposal at that meeting. The original deadline for providing conceptual proposals was the February meeting, but we will extend it to the March meeting. If you have a

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conceptual proposal that you would like to present, please let me know as soon as possible, but no later than 12:00 noon on Tuesday, March 11, so that we can notify all parties.

CDWR-SWP Summary of Position

At the February 19, 2003 meeting, CDWR-SWP distributed a ***Summary of Position***. An electronic copy of this document is now available on the 2004 GMC main page at:

http://www.caiso.com/docs/2003/02/07/2003020716402314262.html

or by clicking on this URL:

http://www.caiso.com/docs/09003a6080/1f/a2/09003a60801fa2bc.pdf.

Updated aggregated billing determinant data

The aggregated billing determinant data that was previously distributed has been updated. An error was found in the monthly gross energy numbers. The error was an incorrect sorting of the monthly numbers (for which I take responsibility). The totals were unaffected. No other changes were made to any other data. A spreadsheet containing the updated information, as well as the other unchanged data is attached.

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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RE Market Issues Forum presentation 03-12-03.txt

From: Arikawa, Ben
Sent: Wednesday, March 12, 2003 8:31 AM
To: Pritchard, Jan; Arikawa, Ben
Cc: Neal, Sean; Kirsch, Laurence; rchemphill@lrca.com; MIKE KREAMER; ROGER VANHOY; Morrison, Stephen; Leiber, Phil
Subject: RE: Market Issues Forum presentation

Jan,

I always put the URL of the GMC web page on the presentations. The objective is to get parties interested, to have them review documents,

and to have them participate to the extent that they have an interest.

The MID's most recent document should be posted as soon as Stephen is reasonably assured that the document contains no confidential information. I will follow-up with him today on that.

I will send you a copy of the presentation as soon as it is posted later this afternoon.

-----Original Message-----
From: JAN PRITCHARD [mailto:JanP@MID.ORG]
Sent: Tuesday, March 11, 2003 2:24 PM
To: BArikawa@caiso.com
Cc: SMN@dwgp.com; lkirsch@lrca.com; rchemphill@lrca.com; MIKE KREAMER; ROGER VANHOY
Subject: Re: Market Issues Forum presentation

Ben,

MID does not plan to attend the MIF. Would you please inform the attendees where they can get a copy of the MID proposal and invite those
interested in further discussion to participate in the March 17 conference call?

Thanks

Jan

2BBYvx.370000000.9914

>>> "Arikawa, Ben" <BArikawa@caiso.com> 03/11/03 10:54AM >>>
Jan, Laurence and Ross,

RE Market Issues Forum presentation 03-12-03.txt

I will be making a presentation at the Market Issues Forum on the status of the GMC proceedings. As part of that I will summarize the MID and Edison proposals and defer most detailed questions to MID or Edison.

I'm scheduled for 11:00 -11:45 Thursday. The call in number is (888) 803-5681. It's listen only.

Note: the attached documents are circulated by the sender solely for the express purpose of informing discussion. Therefore, none of the contents may be regarded by the reader as any form of offer, undertaking, policy, proposal or commitment by the sender, author or the California ISO.

Ben Arikawa
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CALIFORNIA ISO

California Independent
System Operator

Status Report:
Grid Management Charge

March 13, 2003

Market Issues Forum

Ben T. Arikawa
Senior Financial Analyst
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(916) 608-5958

Exh. No. ISO- 216, Page 1 of 17

Disclaimer

This presentation is circulated solely for the express purpose of informing discussion. Therefore, none of the contents may be regarded by the reader as any form of offer, undertaking, policy, proposal or commitment by the author or the California ISO. ISO Summaries of non-ISO proposals are intended as a guide only.

Exh. No. ISO- 216, Page 2 of 17

Topics

- 2004 GMC Rate Structure Project
  - Purpose of Project
  - Project Materials
  - Meetings
  - Participants
  - Alternative Proposals
  - Next steps

Exh. No. ISO-216, Page 3 of 17

Purpose of 2004 GMC Rate Structure Project

- Initial Decision in ER01-313-000, et.al.
  - Requires ISO to reevaluate its rate structure
  - Requires evaluation of different proposals
- Settlement in ER02-250-000, et. al
- Analyze different rate structures
- Develop basis for new ISO rate structure effective January 1, 2004

Exh. No. ISO- 216, Page 4 of 17

2004 GMC Rate Structure Project Materials

- 2004 GMC Rate Structure Project web page on CAISO website
  - Documents
  - Public Discussion Board
  - Confidential Discussion Board
  - Accessible from http://www.caiso.com/docs/2002/08/02/2002080216283419989.html

Exh. No. ISO- 216, Page 5 of 17

Past 2004 GMC Rate Structure Project Events

- August 31, 2002 – conference call
- October 9, 2002 - meeting at ISO
- November 8, 2002– meeting at ISO
- December 9, 2002– meeting at ISO
- December 13 and 23, 2002 – conference calls
- January 13, 2003 – meeting at ISO
- January 16, 23, and 30, 2003 – conference calls with MID
- February 3 – 10, 2003 – conference calls with MID
- February 19, 2003 - – meeting at PG&E
- March 4, 2003 – conference call

Participants

- Participants
  - CAC/EPUC, CDWR/SWP, CMUA, CPUC, EMS, EOB, FERC staff, IEP, MID, NCPA, Navigant (representing municipal utilities), PG&E, SCE, Sempra, TID, WAPA

Alternative Proposals

- Southern California Edison – Bert Hansen
- Modesto Irrigation District – Dr. Laurence Kirsch, Christensen Associates
- California ISO – Phil Leiber

Exh. No. ISO- 216, Page 8 of 17

Brief Summary of SCE Conceptual Rate Proposal

- Five rate components
  - Control Area Services (CAS)
  - Dynamic Dispatch Export Services (DDES)
  - Scheduling Service (SS)
  - Market Operation Services (MOS)
  - Real Time Operation Services (RTOS)

Exh. No. ISO-216, Page 9 of 17

Brief Summary of SCE Conceptual Rate Proposal (cont.)

- Control Area Services charge (net control area load)
- Dynamic Dispatch Export Services (MWhs dynamically dispatched to other control areas over transmission lines owned by other entities)
- Entity pays CAS or DDES, but not both

Exh. No. ISO- 216, Page 10 of 17

Brief Summary of SCE Conceptual Rate Proposal (cont.)

- Scheduling Service (MWhs of energy scheduled plus self-provided ancillary services)
- Market Operations Service (MWhs of energy purchased or sold in CAISO markets)
- Real Time Operations Services (MWhs of uninstructed imbalance energy)

Exh. No. ISO-216, Page 11 of 17

Brief Summary of MID Rate Proposal

- Four rate components
  - Resolving Energy Imbalances
  - Managing Transmission Flows
  - Administering Markets
  - Scheduling Generation, Load and Transmission Facilities

Exh. No. ISO- 216, Page 12 of 17

Brief Summary of MID Rate Proposal (cont.)

- Resolving Energy Imbalances
  - Demand charge (maximum net uninstructed deviations over prior 12 months)
  - Energy charge (net uninstructed deviations)
  - Customer charge (per customer-month)
- Managing Transmission Flows
  - Demand charge (maximum power withdrawals from grid)
  - Energy Charge (power withdrawals with grid)
  - Customer charge (per customer-month)

Brief Summary of MID Rate Proposal (cont.)

- Administering Markets
  - Energy charge (purchases and sales of Ancillary Services and Real Time energy)
- Scheduling Generation, Load and Transmission Facilities
  - Not currently proposed
  - MID proposed during 2001 GMC proceeding, but FERC Staff raised issues

Exh. No. ISO- 216, Page 14 of 17

Brief Summary of CAISO Conceptual Rate Proposal

- Five rate components
  - Core Reliability Services
  - Energy & Transmission Services
  - Scheduling Service
  - Market Service
  - Customer Service

Exh. No. ISO- 216, Page 15 of 17

Brief Summary of CAISO Conceptual Rate Proposal (cont.)

- Core Reliability Services
  - Potentially demand based (gross)
- Energy & Transmission Services
  - Energy charge – net control area load plus exports
- Scheduling Service
  - Transactions charge – per unit of activity (may be scaled for size of activity)
- Market Service
  - Energy charge
  - Potentially transactions based
- Customer Service
  - Fixed charge – per customer (may be scaled for level of activity within CAISO)

Exh. No. ISO- 216, Page 16 of 17

Next Steps

- Conference call – March 17th, 2003
- Timeline
  - April – Discuss more fully fleshed out Edison and CAISO proposals, develop indicative rates
  - May – Analyze bill impacts,
  - June – Presentation to CAISO Board
  - June – July – Incorporation into CAISO Budget Process
  - November – FERC filing

Exh. No. ISO- 216, Page 17 of 17

California Independent
System Operator

Proposed Agenda for Conference Call
2004 GMC Stakeholder Process
March 17, 2003
10:00 a.m. to 12:00 p.m.
Conference Call-in #1-888-788-6681
Passcode: 921065

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)

Navigant CONSULTING, INC.

MEMORANDUM

DATE: February 10, 2003

TO: Ben Arikawa, Phil Leiber

FROM: David B. Cohen

SUBJECT: CAISO INDIRECT COSTS

Note: This document was prepared for the express purpose of starting a discussion and furthering the evaluation. Therefore, none of the contents may be regarded by the reader as any form of offer, undertaking, policy, proposal or commitment by the sender.

2004 GMC Rate Structure Project[1] - a Stakeholder Process

The 2004 GMC Rate Structure Project is being performed in part to respond to the FERC Administrative Law Judge's 2001 GMC Initial Decision (ID) in ER01-313-000. In the ID the ALJ stated, "Rather, the entire GMC should be examined in totality and any restructuring or reallocations should be proposed and implemented in that overall context." [ID at page 50]. During the course of the hearing "The ISO agrees that there is always room for improvement, and the ISO is willing to entertain improvements in subsequent budget iterations. *Id.* 49:21-50:20".

A tool to assist the 2004 GMC Rate Structure Project is using the 2003 GMC Budget and Cost Allocation Matrix (CAM) for informational and discussion purposes. Examining the CAISO's 2003 Budget, reveals approximately $60 million out of $171.7 million of Operating Expenses (or 35 percent) are identified as Indirect Costs.

As part of a 2004 GMC Rate Structure Project there needs to be examination of all Cost Centers (Direct and Indirect) to determine if breakdown of previously identified Indirect costs can be achieved as part of the review that is being undertaken. The attached table identifies the Indirect Operating Costs in the 2003 CAISO Budget.
The CAISO Staff should have two working sessions in the latter part of February or early March 2003 to review all Indirect Cost Centers, with Stakeholders, to find out if further direct assignments to cost centers are reasonable.

Please advise all stakeholders of how the CAISO plans to address this issue.

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[1] Rate Structure includes: determination of services provided (current and future), accumulation of overall costs, cost allocation, rate design (including billing determinants). While not the primary focus of this group, the overall level of ISO costs (also referred to as the ISO revenue requirement) is of concern to ISO stakeholders, and consideration of a mechanism to adequately address this issue prospectively may be necessary.

ISO DEPT #	OPERATING COSTS	TOTAL COSTS
1500	Operations - Indirect Costs	
1511	VP Grid Operations - General	$1,011,957
1547	Engineering and Maintenance - General	$1,154,222
1548	OSAT	$267,932
1564	Operations Scheduling - General	$322,862
Total Operations Indirect Costs		$2,756,973
1700	Market Services - Indirect Costs	
1711	VP Market Services - General	$248,117
1721	Billing and Settlements-General	$353,911
1751	Market Operations - General	$959,968
Total Market Services Indirect Costs		$1,561,996
1400	VP Information Services Indirect Costs	
1411	Chief Information Officer- General	$212,246
	Corporate & Enterprise Applications -	
1422	General	$248,320
1466	Enterprise Applications	$816,499
1431	End User Support	$6,565,001
1432	Computer Operations - General	$430,975
1433	Network Operations	$1,629,905
1442	Production Support	$2,581,165
1451	Information Security	$1,509,500
1463	Operations Applications - General	$323,539
1471	IT Planning	$770,116
1468	Corporate Application Support	$1,333,287
1469	Analytical and Reporting	$1,055,106
1481	Markets and Scheduling	$1,520,628
Total IS Indirect Costs		$18,996,287

ISO DEPT #	OPERATING COSTS	TOTAL COST
1300	Finance - Corporate Indirect Costs	
1321	Accounting	$2,168,530
1331	Financial Planning and Treasury	$2,511,009
1351	Facilities	$5,812,962
1361	Office Administration	$2,227,171
Total Finance Indirect Costs		$12,719,672
1311	CFO - General	$424,204
1631	Legal and Regulatory	$13,118,010
1611	VP General Counsel - General	$385,985
1821	Communications	$865,811
1831	Strategic Development	$693,745
1851	Project Office	$657,758
1861	Regulatory Policy	$1,430,767
Total Corporate and Strategic Devpt b/f HR		$3,648,081
1811	VP Corporate and Strategic Development - General	$497,434
1100/1200	CEO / Human Resources - Corporate Indirects	
1111	CEO - General	$730,899
1841	Human Resources	$4,794,842
1651	Board of Governors	$163,100
Total CEO/HR Costs		$5,688,841
	TOTAL INDIRECT COSTS	**$59,797,483**

CALIFORNIA ISO

California Independent
System Operator

ISO Conceptual Rate Structure

2004 GMC Rate Structure Project

For discussion on

March 17, 2003

teleconference

The information in this presentation is preliminary and does not represent the fully developed view of the ISO as to an appropriate GMC rate structure. It was compiled solely for the purpose of furthering discussion and research related to the ISO's '2004 GMC Rate Structure Project'. No implications may be drawn regarding the ISO's ultimate position on any subject in the Project from either the inclusion or exclusion of any specific information in this document.

Exh. No. ISO- 219, Page 1 of 13

Introduction to ISO Rate Structure Concept

- **Objectives**
  - Fulfill project objectives as set forth in project charter.
  - Listen to, and incorporate to the extent feasible, ideas raised by stakeholders in GMC stakeholder process
- **Current ISO Conceptual Rate Structure**
  - Still evolving
  - ISO "still listening" & "still considering"
    - But, ability to modify proposal to include concepts raised in stakeholder process will diminish as Board deadline approaches (May / June).
  - Does not preclude additional changes.

Exh. No. ISO- 219 Page 2of 13

Recent Changes

- **ISO presented initial conceptual rate structure on 2/19 and took comments from stakeholders**
  - Current rate structure concept reflects some changes made as a result of feedback and additional consideration by ISO team.
  - Still considering boundaries of service categories, cost allocation and issues billing related to billing determinants.

CALIFORNIA ISO

California Independent System Operator

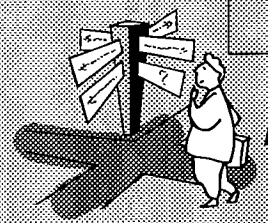
ISO Conceptual Rate Structure

Total Revenue Requirement of ~$240 million

CURRENT	***CAS***	***CONG***	***ASREO***

2/19/2003 Presentation for 2004 Rate Structure	***Reliability Services***		***Market Services***		***Customer Service***
	Core Reliability Services ***1***	**Energy and Transmission Services** ***2***	**Market Infrastructure** ***3***	**Market Usage** ***4***	***5***

Current concept for 2004 Rate Structure	***Reliability Services***		**Scheduling**	***Market Services***	***Customer Service***
	Core Reliability Services ***1***	**Energy and Transmission Services** ***2***	***3***	***4***	***5***



*Notes: **A.** New service category names yet to be determined. The above are merely placeholders.*
***B.** Sizes of boxes do not necessarily represent the proportion of total ISO costs that each may contain.*
***C.** Potential billing determinants discussed on subsequent pages could be used singularly or in combination for each service category/subcategory.*

Exh. No. ISO- 219, Page 4 of 13

1. Core Reliability Services

- Conceptual Description:
  - Core functions essential to the existence of a functioning control area. The minimum staffing, software and facilities necessary to operate a bare-bones control area (as geographically dispersed as the present system but with minimal load). Example: requires five shifts for control room operators, two physical locations to ensure reliability in case of major catastrophe.
- ***Potential*** and preferred Billing Determinants

Coincident peak demand, gross or net	Demand
Maximum non-diversified, non-coincident peak demand, gross or net	Demand
Maximum non-coincident peak demand, gross (may be diversified)	Demand
Monthly gross control area load (energy) plus exports	Volumetric

Preferred

Others?

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2. Energy & Trans. Services

- Conceptual Description:
  - Services performed in a control area operation that fluctuate according to the intensity of use within the control area. This includes the services for simultaneously managing the energy imbalances and the transmission flows in excess of core control area requirements.
- ***Potential*** and preferred Billing Determinants:

Monthly net control area load (energy) plus exports	Volumetric
Sum of the absolute value of maximum hourly SC deviations	Demand
Total of the absolute value of hourly SC deviations	Volumetric

Preferred

Possible Addition

Others?

Exh. No. ISO-219, Page 6 of 13

3. Scheduling Service

- Conceptual Description:
  - Services performed related to Day-Ahead and Hour-Ahead Scheduling.

  - ***Potential*** and preferred Billing Determinants:
    - Considered both transactional and volumetric components, but now leaning toward only transactional.

Number of schedules	Transactional
MWh of Energy and A/S scheduled in final HA schedules. Would include volumes related to inter-SC trades.	Volumetric

Preferred

Others?

4. Market Services

- Conceptual Description:
  - ISO services related to the provision of markets to acquire balancing energy, ancillary services, and annual auctions for FTRs/CRRs.

  - ***Potential*** and preferred Billing Determinants:

Purchases & sales of energy & A/S	Volumetric
FTR MW (Note: if we decide to create a separate charge for FTR/CRR participation)	Demand
SC Maximum Demand for Market Services	Demand

Preferred

Possible Addition

Others?

Exh. No. ISO- 219, Page 8 of 13

5. Customer Service

- Conceptual Description:
  - Services provided to market participants related to metering, billing, settlements, customer relations and training.
- ***Potential*** and preferred Billing Determinants:
  - Developing billing determinant reflective of cost drivers for the above services.

Number of SCs	Customer
No of SC by size category based on transactions and/or maximum demand	Customer

Preferred

Others?

  - Under discussion…roll most costs back to other services?

Exh. No. ISO- 219, Page 9 of 13

Benefits

- Further unbundling (consistent with 2001 ID)
- Addresses concerns raised in litigation
- Addresses issue of matching cost drivers with cost recovery
  - To some extent, matches recovery of fixed costs with demand or customer charges.
  - Likely to incorporate alternative rate designs advocated by participants, such as CPUC.
- Includes changes resulting from ideas raised in stakeholder process.

Preliminary Evaluation

Compared to Current GMC Structure

Favorable | No Change | Unfavorable

Develop a rate structure

- that meets the FERC "just and reasonable" standard, and appropriately allocates ISO costs among the ISO's users. — TBD
- based on the principle of cost causation which charges customers for the cost of services that they use/cause; — TBD
- that is easy to administer (including reasonably cost effective, and benefits of change should outweigh the costs) and understandable; — TBD
- that does not result in unmanageable adverse operational impacts; — TBD
- that is arrived at through an open and balanced stakeholder process; — TBD
- that recovers approved ISO costs in a stable, low risk manner without excess volatility; — TBD
- that is filed with FERC by November 1, 2003, so that it can be effective January 1, 2004, and — TBD
- That meets the terms of the 2002 GMC Settlement Agreement, which set forth issues to be covered in this 2004 GMC Stakeholder Process. — TBD

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To Do...

- Identify issues (implementation, equity, etc.) — Mar
- Develop indicative rates for service categories — Mar
- Provide further assistance in development of other stakeholder proposals — Mar
- Evaluate proposals, customer impact analysis — Apr
- Update Board on Progress — Apr
- Develop consensus proposal? — Apr / May
- Bring to Board for Approval — Jun
- 2004 Budget development — Jul / Aug
- 2004 Rate filing — Nov
- Rating filing support — 2004

Exh. No. ISO- 219, Page 12 of 13

Comments / Discussion

Non-confidential nature of Modesto Irrigation District March 3, 2003 rate proposal document

As noted on the March 4, 2003 conference call, MID provided an MS Word document titled, "Design of The California ISO's Grid Management Charge," which was marked as confidential. The ISO distributed this document prior to a determination of the confidential nature of materials contained in the document. During the conference call, the ISO stated that it would determine the need for confidentiality and report back to participants. The ISO has determined that the document does not contain Confidential Material, though it is based on confidential information. The document is not, therefore, required to be marked as confidential. However, by distributing the document prior to determining its nature, the ISO did not intend to, and does not, waive any confidentiality with respect to the underlying data.

CHRISTENSEN ASSOCIATES

Laurits R. Christensen Associates, Inc.
4610 University Avenue, Suite 700
Madison, Wisconsin 53705-2164

Voice 608.231.2266 Fax 608.231.2108

TO: Ben Arikawa

FROM: Ross Hemphill & Laurence Kirsch

DATE: 3/7/03

SUBJECT: Rate Design of the California ISO's Grid Management Charge

Attached please find our revised proposal for designing the GMC. This revision reflects on stakeholder comments made on the March 4th conference call. The most significant revisions are as follows:

- Per Kathy Yap's suggestion, we explain the rationale for our choices of demand measures.
- We explain why our demand charges should not be a significant cause for SCE's concern that demand charges might be inconsistent with a market design that allows customer switching among SCs.
- We have changed our demand measure for the Managing Transmission Flows function so that it is based upon each separate month's peak rather than upon a rolling 12-month ratcheted peak.

Although we have not revised our proposal to reflect the ISO's tentative move toward unbundling scheduling charges, we wish to reiterate our support for the basic concept of recovering scheduling costs from the customers who cause these costs.

Regarding confidentiality, virtually all of the numbers presented in this proposal are based upon information that has been marked "confidential"; but none of the numbers presented herein reveal any SC-specific information. For this reason, I have not highlighted as confidential any specific text in this proposal.

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 flesh out details of the rate design proposal made by Dr. Kirsch in the California ISO's 2001 Grid Management Charge proceeding.[1] These details include numbers to the extent that we have numbers at this time.

In the spirit of trying to find common ground with the tentative positions expressed by the ISO in its recent presentation entitled *ISO Conceptual Rate Structure*[2], the rate design proposal that we make in this paper reflects two major principles:

- The customers who use the ISO's services should pay for those services to the extent practical.
- Unavoidable fixed costs should be recovered through fixed charges (i.e., demand and customer charges) to an extent consistent with economic efficiency.

To simultaneously adhere to these two principles, we functionalize costs according to the services the ISO provides to customers; and we classify the costs to billing determinants within functions according to the proportions identified by the ISO as fixed or variable. These costs are then allocated by the appropriate billing determinants to derive the rate design. Section 1 discusses functionalization while Section 2 addresses allocation.

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]

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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*, 2004 GMC Rate Structure Project Meeting, San Francisco, February 19, 2003.

[3] The engineering literature repeatedly states that system operators aim to minimize some set of system 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*

- *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, in principle, two of these other services merit 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.
- *Scheduling generators, loads, and transmission facilities* so that SCs can set and update their schedules.

Nonetheless, we note that, in the 2001 Grid Management Charge proceeding, FERC Staff raised questions concerning whether separate scheduling charges were consistent with FERC policy.[4] Because of these questions and because we expect that the dollars related to the scheduling function are relatively small, we will not advocate a separate scheduling function in the 2004 GMC rate proceeding. We may be receptive, however, to the arguments of parties who might advocate charges for this function, depending upon how customers' use of this function is measured.

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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.

[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.

1.2. Cost Assignments for Our Proposed Functions

To facilitate the assignment of costs to our proposed functions, the ISO provided to us 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. After making our cost assignments for these 63 "direct assignment" departments, the spreadsheet automatically assigned the costs of "indirect assignment" departments to our functions. The spreadsheet, which contains confidential information, shows that the ISO's costs are assigned to our functions as follows:

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%

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.

2. CLASSIFYING COSTS AND DESIGNING RATES [5]

In this section, for each of the three functions, we discuss classification of costs as energy, demand, or customer related; and the identification of appropriate billing determinants for designing the rates for each ISO service.

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 imbalance 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, the proposed billing determinants are as follows:

[5] Unless otherwise indicated, Billing determinant data are from the ISO spreadsheet entitled "Aggregated data for distribution.xls."

- *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 are proposing a non-coincident peak measure 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.[6]
- *The customer measure* is the number of SCs.

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.[7]

TABLE 2
BILLING DETERMINANTS
FOR THE RESOLVING ENERGY IMBALANCES FUNCTION

Billing Determinant	Quantity	Data Period
Uninstructed deviation energy	16,786,796 MW-intervals	9/01-8/02
Uninstructed deviation demand (most recent 12 months)[8]	54,276 MW	9/01-6/02
Number of SCs	73 SCs	9/01-6/02

Because we do not have sufficient information to determine how the costs of this function should be classified among the energy, demand, and customer charges, and because the ISO has not yet

[6] 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, and therefore should not be a cause of SCE's concern that demand charges might be inconsistent with a market design that allows customer switching among SCs. See memorandum of Bert Hansen, February 21, 2003.

[7] 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 trend in the data that are available to us.

[8] The interval-by-interval dataset of uninstructed deviations show that, for the period September 2001 through June 2002: a) the maximum absolute deviation for each SC *over the 10-month period*, summed over SCs, is 4,523 MW; and b) the maximum absolute sum of the deviations of the SCs *in any one interval* is 584 MW. "Aggregated data for distribution.xls," sheet "Max Uninstructed Dev demand," shows that the maximum absolute deviation for each SC *in each month*, summed over SCs, ranges between 1,229 MW and 2,289 MW. The substantial (and unsurprising) diversity of imbalances among SCs yields this effect of the billing determinants summing to substantially larger figures over larger periods of time. Because we are proposing the billing determinant be the highest value over the most recent 12-months, the 10-month figure is the one that is most relevant to our proposal. Over the course of a year, this figure is equivalent to 54,276 MW-months (equals 12 months times 4,523 MW).

apportioned costs among its categories, we cannot make a definite rate proposal at this time. In principle, the costs that would be customer-related and classified according to the number of SCs would be those that vary with the number of SCs. Subject to examination of the ISO's methods and results, we might be satisfied to classify the remaining costs between the demand and energy billing determinants in proportion to how the ISO apportions costs between the "Core Reliability Services" and "Energy and Transmission Services" categories that it described in its *ISO Conceptual Rate Structure* presentation. This is consistent with the notion that the first category is mostly fixed costs that are recovered through a demand charge while the second is mostly variable costs that are recovered through a volumetric charge.

Pending information on the ISO's cost apportionment, we present, in Table 3, the rates that would occur if 5% of Resolving Energy Imbalances costs were classified as customer-related and if the remainder were equally classified to the energy and demand charges.[9]

TABLE 3
RATES FOR THE RESOLVING ENERGY IMBALANCES FUNCTION

Billing Determinant	Cost	Quantity	Rate
Uninstructed deviation energy	$20,155,788	16,786,796 MW-intervals	$1.20 / MW-interval
Uninstructed deviation demand (most recent 12 months)	$20,155,788	54,276 MW	$371.36 / MW-month
Number of SCs	$ 2,121,622	73 SCs	$2,422 / customer-month

The level of the charges in Table 3 reflects the level of the ISO's energy balancing costs. We note that 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 an 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.

Although we find the case for a demand charge less compelling for the Managing Transmission Flows function than for the Resolving Energy Imbalances function, we recognize that this is a service that only the ISO can provide, and that it incurs substantial fixed costs to be able to provide it. Hence, we propose that, in each month the billing determinants for this function

[9] 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.

include an energy measure, a demand measure, and a customer measure. For each SC in each month, the proposed billing determinants are as follows:

- *The energy measure* is the sum of the SC's power withdrawals from the ISO-controlled grid.
- *The demand measure* is the SC's maximum hourly power withdrawal from the ISO-controlled grid during the current month.[10] This is a non-coincident peak measure for each separate month (i.e., 12 NCP). We propose a non-coincident peak measure because customers have much better access to information about their own peak power withdrawals than about total power withdrawals, and because the costs of managing transmission flows is more related to local peaks than to system peaks. A monthly demand charge would minimize the inequities that might arise from customer switching among SCs, a concern expressed by SCE.[11]
- *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.

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
Maximum power withdrawals[12]	625,912 MW-months	9/01-8/02
Number of SCs	73 SCs	9/01-6/02

The costs that would be classified according to the number of SCs would be those that vary with the number of SCs. Subject to examination of the ISO's methods and results, we might once again be satisfied to classify the remaining costs between the demand and energy billing determinants in proportion to how the ISO apportions costs between the "Core Reliability Services" and "Energy and Transmission Services" categories that it described in its *ISO Conceptual Rate Structure* presentation. Again, this is consistent with the notion that the first category is mostly fixed costs that are recovered through a demand charge while the second is mostly variable costs that are recovered through a volumetric charge.

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[10] This is a monthly non-coincident peak measure (i.e., 12 NCP).

[11] Memorandum of Bert Hansen, February 21, 2003.

[12] For the 12-month period September 2001 through August 2002, "Aggregated data for distribution.xls" shows that net system energy is 242,457 GWh, gross system energy is 255,754 GWh, and the highest non-coincident peak for gross loads in any month is 55,020 MW. In Table 4, 625,912 MW-months = 12 months * 55,020 MW * 242,457 GWh / 255,754 GWh. Note that, because diversity of customers' loads may cause SCs' annual non-coincident peaks to fall in different months, the 625,912 MW-months figure is likely to be low relative to the actual, so that the required rate is likely to be lower than the $97.36 / MW-month figure shown in Table 5.

Again pending information on the ISO's cost apportionment, we present, in Table 5, the rates that would occur if 5% of Managing Transmission Flows costs were classified as customer-related and if the remainder were equally classified to the energy and demand charges.

TABLE 5
RATES FOR THE MANAGING TRANSMISSION FLOWS FUNCTION

Billing Determinant	Cost	Quantity	Rate
Power withdrawals	$60,940,789	242,456,619 MWh	$0.25 / MWh
Maximum power withdrawals	$60,940,789	625,912 MW-months	$97.36 / MW-month
Number of SCs	$ 6,414,820	73 SCs	$7,323 / customer-month

2.3. Administering Markets

The costs of administering markets should be recovered from the customers who trade in these markets. Measurement of the customers' use of the markets should be according to some combination of the volumes (MWhs) and values (dollars) traded. The measurement should probably differ by the service traded (e.g., energy, spinning reserves, financial transmission rights), though such differences might be captured sufficiently by measures of value 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.

Competition undermines the rationale and practicality of demand and customer charges for two reasons. First, it means 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, the 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 because the customer has nowhere else to go.

Hence, we propose that, in each month the billing determinant for this function be as follows:

- *Trading volumes*, which can be measured by volumes of power traded, preferably with differentiation by the service traded (e.g., energy, spinning reserves).

Table 6 shows the billing determinants and the values that we use for purposes of calculating rates. In the table, trading volumes are measured solely by giving a MWh of energy exactly the same weight as (for example) a MW-h of spinning reserves. Although the experience of competitive commodity markets leads us to believe that differentiation among services is warranted, we use the aggregate MWhs figure for the immediate purpose of this proposal.

TABLE 6
BILLING DETERMINANTS
FOR THE ADMINISTERING MARKETS FUNCTION

Billing Determinant	Quantity	Data Period
Trading volumes	73,374,094 MWh	9/01-8/02

Table 7 shows the consequent rates.

TABLE 7
RATES FOR THE ADMINISTERING MARKETS FUNCTION

Billing Determinant	Cost	Quantity	Rate
Trading volumes	$66,870,735	73,374,094 MWh	$0.91 / MWh

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 FPA 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.

March 24, 2003 – Draft

California Independent
System Operator

Agenda for Conference Call
2004 GMC Stakeholder Process
March 17, 2003
10:00 a.m. to 12:00 p.m.
Conference Call-in #1-888-788-6681
Passcode: 921065

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)

All documents discussed at the meeting are posted on the 2004 GMC Rate Structure Project main page:

http://www.caiso.com/docs/2003/02/07/2003020716402314262.html

The next meeting was scheduled for Friday, April 11th, 10:00 – 3:00 (PST) at the ISO in Folsom. A conference call or meeting was scheduled for April 28th from 10:00 – 2:00 (PST).

The conference call started at about 10:05 with a roll call. The list of participants (who were on for all or part of the call) can be found at the end of these notes.

Introductions/Announcements

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The ISO announced that the documents and data had been posted to the public and private discussion boards. One does not need a username and password to view public documents, but these are required for viewing and downloading documents on the private discussion board. Ben Arikawa will e-mail usernames and passwords to parties over the next few days.

The ISO determined that the March 3, 2003 Modesto Irrigation District document, ***Rate Design Of The California ISO's Grid Management Charge***, did not contain confidential information, though confidential data were used in developing the proposal. In addition, the ISO also determined that the March 7, 2003 revision of that document was not confidential. The ISO had released the March 7th version with a disclaimer.

CPUC Issues

The CPUC was given the first opportunity to ask questions and give comments. The CPUC had sent an e-mail with questions to the ISO. First among these questions was whether the potential errors in the aggregated billing determinant data had been corrected. This issue was first raised by the EOB in an e-mail. The monthly gross control area load plus exports shown in the aggregated billing determinant data spreadsheet was not correct. An incorrect sort of the data had led to the error. For example, September 2001 data was actually August 2002 data. The error had been corrected and spreadsheet had been sent out to the GMC WG e-mail distribution list on Friday, March 7, 2003.

The EOB also questioned whether the difference between gross and net control area load had been properly calculated. The ISO explained to the EOB that the difference between gross and net control area load was small due to the removal from SMUD from the data. SMUD is no longer part of the control area and the billing determinant data should reflect this. Also, the difference is small because it represents only the portion of QF and municipal load that is not metered and not the entirety of QF and municipal load.

The CPUC asked about updated data. In an earlier conference call, the ISO did commit to reviewing more recent billing determinant data to ensure that no adverse trends had appeared. The ISO renewed its commitment.

The CPUC asked several questions concerning the level of effort required to administer Metered Sub-Systems. The ISO requested that the CPUC send an e-mail with the questions directly so that it could be considered.

There was a discussion of next meeting dates. The meeting dates are noted at the beginning of these notes.

SCE Rate Proposal

SCE was asked about its progress on quantification of its proposal. The ISO offered to assist SCE once SCE had progressed sufficiently. The possibility of conference calls was discussed.

MID Rate Proposal

At this point, MID did not have anything additional to request from the ISO.

Jim Ross and David Cohen asked several questions concerning the stability of the billing determinant for the Resolving Energy Imbalances function. Jim Ross asked a hypothetical to illustrate the charges to a generator.

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Peter Kissel and Jing Chao Mi asked several questions concerning the justification for using non-coincident demand peak as one of the billing determinants for Managing Transmission Flows.

David Cohen asked if MID had given thought to on how the ISO's functions matched up with MID's functions. Dr. Kirsch responded that there was some overlap.

Indirect Cost Assignments

David Cohen had previously written a memo to the ISO requesting that the ISO give consideration to directly assigning more of indirect costs. This memo was not discussed during the February 19th meeting, nor the March 4th conference call due to a lack of time.

David was concerned that a significant portion of the ISO's costs ($60 million) remained as indirectly assignable. He urged the ISO to directly assign costs whenever possible. He pointed out that some portion of the $13 million in Legal and Regulatory as costs that should be directly assigned.

He requested a response from the ISO. Phil Leiber commented that the ISO was not opposed to a discussion of this. Parties discussed having a meeting just on this issue. However, no firm date was set.

GMC Tool

The next issue was a discussion of the GMC Tool. Given the evolution of proposals, the ISO did not think that linking cost centers to groupings of activities would be feasible, nor even helpful. This conclusion was not opposed. The ISO would still provide a GMC Tool, but in a format that would contain the basics of all three proposals that would allow comparisons among the proposals.

During this conversation, the EOB was asked if the EOB and CPUC would have a proposal to present. They would not. They would most likely propose tweaks to the ISO proposal.

ISO Conceptual Rate Proposal

The ISO presented its conceptual rate proposal next. The ISO had sent out a presentation on the previous Friday containing the ISO proposal. There had been some changes since the February 19th meeting. Specifically, a Scheduling Services function was now proposed.

Peter Kissel asked several questions concerning the activities in the Core Reliability Services function. The ISO explained the rationale for this function and the type of documentation that it was putting together.

There was discussion of each of the rate functions. The ISO thought that a fully fleshed out proposal with quantification would be available prior to the next meeting on April 11th.

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List of Parties on March 17, 2003 Conference Call
2004 GMC Rate Structure Project

Aoki	Rod	CAC	(415) 421-4143	rsa@a-klaw.com	x
Arikawa	Ben	ISO	(916) 608-5958	barikawa@caiso.com	x
Barkovich	Barbara	Barkovich and Yap			x
Bonaly	David	CDWR			x
Brommer	Mike	TID	(209) 883-8320	mtbrommer@tid.org	x
Cohen	David	Navigant Consulting	(503) 708-7852	dcohen@navigantconsulting.com	x
Hansen	Bert	SCE	(626) 302-3649	berton.hansen@sce.com	x
Kirsch	Laurence	Christensen Associates	(415) 663-8608	lkirsch@lrca.com	x
Kissel	Peter	CDWR			x
Lam	Tony	EOB	(916) 322-8632	tlam@eob.ca.gov	x
Leiber	Phil	ISO	(916) 351-2168	pleiber@caiso.com	x
LeVine	Debi	ISO	(916) 351-2144	dlevine@caiso.com	x
McGuffin	Mike	ISO	(916) 608-5753	mmcguffin@caiso.com	x
Mi	JingChao	CDWR	(916) 653-1095	jmi@water.ca.gov	x
Morrison	Stephen	ISO	(916) 608-7143	smorrison@caiso.com	x
Neal	Sean	MID			x
Pritchard	Jan	MID	(209) 526-7490	janp@mid.org	x
Regan	William	ISO	(916) 351-4450	wregan@caiso.com	x
Ross	James	CAC	(626) 530-9544	jimross@r-e-s-inc.com	x
Schoenbeck	Don	CAC/EPUC		dws@keywaycorp.com	x
Shea	Karen	CPUC	(415) 703-5404	kms@cpuc.ca.gov	x
Siegel	Elaine	ISO			x
Takehara	James	NCPA	(916) 781-4293	james.takehara@ncpa.com	x
Terry	Lee	CDWR	(916) 653-3327	lterry@water.ca.gov	x
Withrow	David	ISO	(916) 608-7134	dwithrow@caiso.com	x
Wolfe	Lisa	EOB	(916) 322-8613	lwolfe@eob.ca.gov	x
Yakin	Dale	PG&E	(415) 973-1752	dgy4@pge.com	x

Created by: Ben Arikawa CAISO LSUPDT: 03/25/03

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Agenda for Conference Call with SCE on its Rate Proposal

2004 GMC Stakeholder Process
Wednesday, April 2, 2003
9:00 a.m. to 10:30 a.m.
Conference Call-in #1-888-788-6681
Passcode: 921065

- 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

Conference call notes and attendance list are below.

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Notes to April 2, 2003 conference call with Southern California Edison.

On April 1, 2003, Bert Hansen had e-mailed a description of the Dynamic Dispatch Export Service (DDES) to the GMC WG e-mail group. That e-mail is currently posted on the ISO's GMC web page under the April 2, 2003 conference call heading.

The conference call began with SCE giving a brief overview of their proposed DDES. This charge would only apply to energy from a resource within the Control Area that was dynamically dispatched by another control area and exported to that control area. The receiving control area, not the "sending" control area, is responsible for correcting any deviations and maintaining the Area Control Error within limits.

Pointing to his April 1st e-mail, Bert stated that SCE believed that the DDES charge should be approximately 10 percent of the current Control Area Services charge on a unit basis (about $0.056 per MWh). SCE was offering to forgo a full-blown cost allocation for a DDES charge if parties were willing to discuss it as a special deal outside the context of the 2004 GMC Rate Structure Project.

Bert stated that he thought only Mohave qualified for the DDES charge. At this time, no one on the call voiced an opinion if this was correct.

There was a discussion between Bert and Stephen Morrison concerning the circumstances surrounding Mohave and how that was different from that of the Southwest Power Link (SWPL). Bert emphasized that it was only a rate issue and not an operational one. There would be no change in operation of Mohave as a result of the DDES.

Bert stated that SCE believed that it should not pay any amount on the energy exported from Mohave, but that the DDES charge was a compromise. SCE was waiting for other parties' reaction to Bert's e-mail. As of the time of the conference call, Bert had only received comments from JingChao Mi of CDWR.

Bert also believed that it was possible that the DDES charge or an exemption from full payment of the Control Area Services (or equivalent) charge might be short-lived. It was possible that Mohave might shutdown in 2005 due to the need for costly pollution retrofits and water issues.

The discussion next turned to SCE's proposed Control Area Services function. This differs from the ISO's current CAS function in that it includes some portion of congestion management and does not include the costs of the DDES.

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The Scheduling Service function included Day-Ahead and Hour-Ahead scheduling activities, but did not include intertie scheduling, which would be in CAS. Self-provided Ancillary Service schedules would be assessed this charge. There would be no charge for zero MWh schedules and for non-winning AS bids. Final Hour-Ahead schedules would be assessed this charge.

There was some discussion of the ISO proposal at this point.

The Market Operations charge would include Day-Ahead and Hour-Ahead market activities. Congestion management costs would go to either CAS or Scheduling Services.

Real-Time Market Operations Service would include actual real time operations, ***e.g.***, Real Time Grid Resource Coordinators.

The ISO offered to assist SCE with developing the costs assignments for their proposal. SCE had a version of the Cost Allocation Matrix. SCE needed additional billing determinants: MWhs underlying Schedules (including self-provided AS MWs) and total uninstructed energy. The ISO would work on providing these to SCE.

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Parties Identified on April 2, 2003 Conference Call with Southern California Edison

Last Name	First	Company	Telephone	E-mail Address	On call
Aoki	Rod	CAC	(415) 421-4143	rsa@a-klaw.com	x
Arikawa	Ben	ISO	(916) 608-5958	barikawa@caiso.com	x
Hansen	Bert	SCE	(626) 302-3649	berton.hansen@sce.com	x
Kehrein	Carolyn	EMS	(707) 678-9506	cmkehrein@ems-ca.com	x
Leiber	Phil	ISO	(916) 351-2168	pleiber@caiso.com	x
Mi	JingChao	CDWR	(916) 653-1095	jmi@water.ca.gov	x
Morrison	Stephen	ISO	(916) 608-7143	smorrison@caiso.com	x
Regan	William	ISO	(916) 351-4450	wregan@caiso.com	x
Springer	John	ISO			x
Timson	David	ISO			x

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-----Original Message-----
From: Berton.Hansen@sce.com [mailto:Berton.Hansen@sce.com]
Sent: Tuesday, April 01, 2003 1:05 PM
To: GMCWG@caiso.com
Subject: SCE DDES Proposal

SCE is submitting this proposal to the 2004 GMC Stakeholder participants in the hope that one issue may be resolved, so that attention may be focused on remaining issues under consideration.

One element of SCE's "Initial Conceptual Proposal" for the ISO's 2004 GMC is a "Dynamic Dispatch Export Service" (DDES). This service would be available to all energy that is dynamically dispatched from the ISO Control Area to other Control Areas over transmission lines owned by other entities, the non-PTO-owned shares of which were not turned over to ISO Operational Control. An example of energy that would be eligible for this service is the generation from the Mohave unit that is owned by Nevada Power, SRP, and LADWP. (LADWP, however, already has been exempted from all GMC charges and thus would be exempt from this charge as well.) The remaining 56% portion of the Mohave output is owned by SCE, is used to serve SCE load, and would pay any charge that Control Area Gross Load pays.

Dynamic dispatch refers to the real-time dispatch of energy from a generator physically located in one Control Area to serve load within a neighboring Control Area. Dynamic dispatch is accomplished by making real-time schedule adjustments (Dynamic Schedules) between the Control Areas based on the respective Control Area's percentage of real-time output from the generator. Each Control Area then considers the Dynamic Schedule in its Net Scheduled Interchange. For example, if 100% of the output of a generator physically located within Control Area A was dynamically dispatched to Control Area B, then the output of that generator would be subtracted from Control Area A's Net Schedule Interchange and added to Control Area B's Net Scheduled Interchange. If the generator were to trip, Control Area B would incur an "Area Control Error" (ACE) deviation that it would have to resolve. Control Area A's ACE would not be impacted by the tripping of the generating unit.

The basis for SCE's proposal is that the ISO does significantly less in terms of Control Area Services for this energy than for the remainder of Control Area Gross Load and exports. The energy that would be eligible for this charge is not the "load responsibility" of the CAISO, as that term is defined by the WECC. As stipulated by NERC Policy 1, the respective Control Area is to include all Dynamic Schedules in the calculation of Net Scheduled Interchange for its ACE calculation and is to consider such load as its "load responsibility". Therefore, the Control Area receiving such Dynamic Schedules has the responsibility to perform all reliability functions for that energy, including transmission planning, provision of ancillary services, and the real-time balancing of resources and loads.

The ISO has identified the following activities whose costs are recovered through the CAS:

1) Performing operation studies;
2) System security analyses;
3) Transmission maintenance standards
4) System planning to ensure overall reliability;
5) Integration with other Control Areas;
6) Emergency management;
7) Outage coordination;
8) Transmission planning;
9) Scheduling generation, imports, exports, and wheeling in the Day-Ahead and Hour-Ahead of actual operations.

SCE's assessment is that of these activities, the only ones that the ISO performs for DDES energy would be "Integration with other Control Areas" and "Emergency Management". SCE's perception is that the costs that the ISO incurs for these two activities are relatively minor.

SCE's Initial Conceptual Proposal contemplated that the rate for the DDES charge would be developed through a cost-allocation process similar to the other charges. In the interest of simplifying SCE's Proposal, and any other proposal such as the ISO's that would assess a charge to this energy, SCE would like to propose an alternative method of dealing with energy that would be eligible for the DDES.

SCE's proposal is that, rather than going through a full cost allocation to develop the DDES charge, that a rate be developed as a percentage of the otherwise applicable rate under the remaining GMC structure. The otherwise applicable rate under SCE's proposal would be the Control Area Services charge. Under the ISO's proposal, as it currently is stated, the otherwise applicable rate would be the "Core Reliability Services" charge. Any revenues collected under this reduced rate would then be credited to the "otherwise applicable rate" in developing its cost of service based rate.

SCE proposes that the percentage would be 10%. SCE's review of ISO budget information filed for the 2001 GMC has indicated that 75% of the costs allocated to the CAS by the ISO can easily be identified as not related to the above two activities. SCE expects that a full cost-allocation effort would demonstrate that a greater amount should be excluded.

The financial impact of a rate for DDES equal to 10% of the otherwise applicable charge would be minimal on the CAS paid by other Control Area Gross Load. Under the current GMC rate structure, about $1.5 million CAS costs are billed to energy that would be eligible for this rate. If the rate were set equal to 10%, then the lost revenue would amount to $1.35 million. Based on the 2003 costs allocated to the CAS of $137.9 million, this amount represents only 1% of the total.

SCE welcomes any comments from the stakeholders in the 2004 GMC review process in the hope that a resolution of this issue may be reached.

From: CRCommunications
Sent: Thursday, April 03, 2003 12:15 PM
To: ISO Market Participants
Subject: CAISO Notice: Stakeholder Meeting - 2004 GMC Rate Structure Project

MARKET NOTICE

April 3, 2003

In Re:

FERC Decision in ER01- 313- 000, Settlement in ER02- 250- 000
Stakeholder Meeting - 2004 GMC Rate Structure Project

April 11, 2003
Location: California ISO, Folsom
Call in number: 1-888-78-6681
Passcode: 921065

ISO Market Participants:
On April 11, 2003 the California ISO ("ISO") will hold a stakeholder meeting to discuss the 2004 Grid Management Charge ("GMC") Rate Structure Project. The meeting will be from 10:00 a.m. to 3:00 p.m. at the California ISO in Folsom.

Background
Following Judicial direction from the Federal Regulatory Energy Commission, the ISO, initiated the "2004 GMC Rate Structure Project" in mid-summer 2002 to review comprehensively the existing GMC structure and to develop a new GMC rate structure to be in place by January 2004. This review is open to all Stakeholders and has involved the active participation of a number of entities thus far. In past meetings, participants and the ISO have reviewed the structure of Stakeholder participation, rate structures of other ISOs, FERC Staff views on ISO rates as a formula rate, various rate methodologies, ISO activities, data requirements for development of rate proposals and rate proposals from the Modesto Irrigation District, Southern California Edison and the ISO. The next Project meeting will be on April 11, 2003 as noted above. Additional information regarding past Project activities is accessible in the ISO web site at: http://www.caiso.com/docs/2002/08/02/2002080216283419989.html.

Process Moving Forward
To date, the ISO has requested that participants in the Project provide input on various rate design elements in order to assist the ISO in developing a revised GMC structure and methodology. The ISO has also asked participants to present their own rate structure proposals.

At the April 11th meeting, Southern California Edison and the California ISO will make detailed presentations of their rate proposals. The Modesto Irrigation District has already made a detailed proposal, which was discussed on a March 4, 2003 conference call.
As the Project moves forward, the ISO emphasizes that the Project is open and encourages participation from entities that have not yet contributed.

If you would like to attend the April 11th meeting, please RSVP to Michelle Gamble (mgamble@caiso.com <mailto:mgamble@caiso.com> or (916) 351-2118) by 12:00 PM on April 8th. We would like an accurate count to ensure that adequate space and food are available. The agenda, presentation materials and meeting location specifics will be emailed to those on the GMC WG distribution list prior to the meeting.
If you would like to be placed on the distribution list for announcements and documents for the 2004 GMC Rate Structure Project, please email Michelle at the address above. Please ask to be added to the GMC WG distribution list.
For more information concerning the 2004 GMC Rate Structure Project, please contact: Ben Arikawa (barikawa@caiso.com <mailto:barikawa@caiso.com>, 916.608.5958) or Phil Leiber (pleiber@caiso.com <mailto:pleiber@caiso.com>, 916.351.2168).

Client Relations Communications11.20
CRCommunications@caiso.com <mailto:CRCommunications@caiso.com>

2004 GMC Rate Structure Project Briefing

To: Participants in 2004 GMC Rate Structure Project

From: Ben T. Arikawa, Senior Financial Analyst

Date: April 4, 2003

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

This Briefing contains:

- Notes for the March 17, 2003 conference call;
- Draft notes for the April 2, 2003 conference call with SCE;
- Availability of documents on public and private discussion boards;
- Closure of the period for presenting full rate structure proposals;
- Proposed Agenda for April 11, 2003 meeting at the California ISO; and,
- Availability of ISO detailed rate proposal.

Notes for March 17, 2003 conference call

Notes to the March 17, 2003 conference call were finalized and posted on the GMC web page. The web page can be accessed from:

http://www.caiso.com/docs/2002/08/02/2002080216283419989.html . The notes can be found under the March 17, 2003 conference call header.

We only received comments from MID. These comments were incorporated into the notes. Other minor changes were made to more adequately reflect the discussion during the conference call.

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Draft notes for the April 2, 2003 conference call with SCE

Draft notes for the April 2, 2003 conference call with SCE were e-mailed to the GMC WG on April 3rd. The draft notes are also available on the public discussion board at:

http://www1.caiso.com/discus/messages/875/875.html . They were posted to the public discussion board on April 4th.

Please review the notes and send edits or comments to Ben Arikawa (barikawa@caiso.com) by COB April 8, 2003.

Availability of documents on the public and private discussion boards

Some documents have been posted to the public and private discussion boards. You do not need a username and password to view and post comments or documents on the public discussion board. However, a username will allow you to set options that, for example, would allow you to receive an e-mail notice if something is posted to the board. If you would like a username and password for the public discussion board, please send an e-mail request to Ben Arikawa (barikawa@caiso.com).

Access to the private discussion board is restricted to those parties that have executed a Confidentiality Agreement and a Non-disclosure Certificate. As they are released, confidential documents will be posted to the private discussion board. If you would like a username and password for the private discussion board, please send an e-mail request to Ben Arikawa (barikawa@caiso.com).

Individuals have the ability to post a document to the public or private discussion boards. To do this, just include the following in the text of the message: **\attach{description of the document}**. In the brackets include a short description of the document you wish to post. When you have completed your message, click on **Preview/Post Message.** You will have an opportunity to review your message prior to final submission. If there are no edits, click on **Post this Message.** You will be prompted to enter the name of the document to upload. You click the **Browse** button to find the document. Click the **Open** button, then **Upload** to begin the upload. Your message will not post immediately, but will be reviewed prior to final posting.

Closure of the period for presenting new rate proposals

Given the lack of further time for consideration in the 2004 GMC Rate Structure Project, the ISO can no longer accept new rate proposals from parties. The original timeline had parties making presentations on their rate proposals by the February 19, 2003 meeting, though the ISO did not foreclose the opportunity to make proposals by the March 17, 2003 conference call. As no new proposals were forthcoming by the conference call, we must proceed with the three proposals before us. However, we do encourage parties to propose modifications that enhance proposals.

Proposed Agenda for April 11, 2003 meeting at the California ISO.

The proposed agenda for the April 11, 2003 meeting at the ISO is posted on the GMC web page. If you have comments on or would like changes to the agenda, please let us know. A market notice was issued on April 3rd announcing the meeting. If you have not yet RVSP'ed, please do so as soon as possible. We have limited space for this meeting and we need to know if a larger room will be needed.

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The market notice can be accessed by clicking on this link:

http://www.caiso.com/docs/09003a6080/20/99/09003a6080209951.pdf .

Availability of ISO detailed rate proposal

As mentioned on the March 17, 2003 conference call, the ISO will provide a working paper and other documents on its proposal prior to the meeting on April 11th. At this time, we believe that these should be distributed on Wednesday, April 9th. If there are confidential documents related to the white paper, we will post them to the private discussion board, so that parties to the Confidentiality Agreement and the Non-Disclosure Certificate may download them.

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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From: Arikawa, Ben
Sent: Monday, April 07, 2003 11:54 AM
To: 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
Subject: Assistance to SCE on GMC Rate Structure Project

Bert Hansen of SCE has requested our assistance as part of the 2004 GMC Rate Structure Project. SCE is developing their own rate proposal for this Project. This e-mail is to ask if you are available to answer questions from SCE in your respective areas. We are not holding individual conference calls for SCE. Instead, we will be giving SCE a contact list with your names and contact information. I do not anticipate that SCE's questions will be overly burdensome.

If you are not the correct person for SCE to contact, please let me know as soon as possible who would be the correct contact.

I will send out an email with the SCE proposal and the template that we sent Bert shortly.

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Ben Arikawa
Senior Financial Analyst
California Independent System Operator
151 Blue Ravine Road
Folsom, CA 95630

Voice: (916) 608-5958
fax: (916) 351-2259

email: barikawa@caiso.com

From: Arikawa, Ben
Sent: Monday, April 07, 2003 11:57 AM
To: Hansen, Bert
Subject: Contacts

Bert,

To get you started, the contacts for Grid Ops are:

Deane Lyon dlyon@caiso.com 916.351.2428
David Hawkins dhawkins@caiso.com 916.351.4465

The contacts for Finance and Accounting are:

Phil Leiber (Finance) pleiber@caiso.com 916.351.2168
Jan Cogdill (Capital, MD02) jcogdill@caiso.com 916.351.2302

I'll send you a complete list once I've been able to contact all of the relevant staff.

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Contact List for Southern California Edison
For assistance in developing their rate proposal in the
2004 GMC Rate Structure Project

Grid Operations
Deane Lyon dlyon@caiso.com 916.351.2428
David Hawkins dhawkins@caiso.com 916.351.4465

Market Operations
Jim McClain jmcclain@caiso.com 916.608.5809
Ziad Alaywan zalaywan@caiso.com 916.351.2140

Market Services
Debi Le Vine (Contracts and Special Projects) dlevine@caiso.com 916.351.2144
Mike McGuffin (Settlements) mmcguffin@caiso.com 916.608.5753
David Timson (Client Relations) dtimson@caiso.com 916.608.7065
Kyle Hoffman (Client Relations) khoffman@caiso.com 916.608.7057

Accounting and Finance
Phil Leiber (Finance) pleiber@caiso.com 916.351.2168
Jan Cogdill (Capital, MD02) jcogdill@caiso.com 916.351.2302

Information Services
Bruce Drummond bdrummond@caiso.com 916.608.5752
Greta Ossman gossman@caiso.com 916.351.2109

Legal and Regulatory
Keith Casey (Market Analysis) kcasey@caiso.com 916.608.7125
Eric Leuze (Compliance) eleuze@caiso.com 916.351.2393

From: Arikawa, Ben
Sent: Wednesday, April 09, 2003 8:43 AM
To: Hansen, Bert
Cc: Morrison, Stephen; Leiber, Phil
Subject: Contact list

Bert,

Here is a contact list for the different departments. If you have any problems getting through to people, please give me a call.

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MARKET NOTICE

April 3, 2003

In Re: FERC Decision in ER01- 313- 000, Settlement in ER02- 250- 000

Stakeholder Meeting - 2004 GMC Rate Structure Project

April 11, 2003
Location: California ISO, Folsom
Call in number: 1-888-78-6681
Passcode: 921065

ISO Market Participants:

On April 11, 2003 the California ISO ("ISO") will hold a stakeholder meeting to discuss the 2004 Grid Management Charge ("GMC") Rate Structure Project. The meeting will be from 10:00 a.m. to 3:00 p.m. at the California ISO in Folsom.

Background

Following Judicial direction from the Federal Regulatory Energy Commission, the ISO, initiated the "2004 GMC Rate Structure Project" in mid-summer 2002 to review comprehensively the existing GMC structure and to develop a new GMC rate structure to be in place by January 2004. This review is open to all Stakeholders and has involved the active participation of a number of entities thus far. In past meetings, participants and the ISO have reviewed the structure of Stakeholder participation, rate structures of other ISOs, FERC Staff views on ISO rates as a formula rate, various rate methodologies, ISO activities, data requirements for development of rate proposals and rate proposals from the Modesto Irrigation District, Southern California Edison and the ISO. The next Project meeting will be on April 11, 2003 as noted above. Additional information regarding past Project activities is accessible in the ISO web site at:
http://www.caiso.com/docs/2002/08/02/2002080216283419989.html.

Process Moving Forward

To date, the ISO has requested that participants in the Project provide input on various rate design elements in order to assist the ISO in developing a revised GMC structure and methodology. The ISO has also asked participants to present their own rate structure proposals.

At the April 11th meeting, Southern California Edison and the California ISO will make detailed presentations of their rate proposals. The Modesto Irrigation District has already made a detailed proposal, which was discussed on a March 4, 2003 conference call.

As the Project moves forward, the ISO emphasizes that the Project is open and encourages participation from entities that have not yet contributed.

If you would like to attend the April 11th meeting, please RSVP to Michelle Gamble (mgamble@caiso.com <mailto:mgamble@caiso.com> or (916) 351-2118) by 12:00 PM on April 8th. We would like an accurate count to ensure that adequate space and food are available.

The agenda, presentation materials and meeting location specifics will be emailed to those on the GMC WG distribution list prior to the meeting.

If you would like to be placed on the distribution list for announcements and documents for the 2004 GMC Rate Structure Project, please email Michelle at the address above. Please ask to be added to the GMC WG distribution list.

For more information concerning the 2004 GMC Rate Structure Project, please contact: Ben Arikawa (barikawa@caiso.com, 916.608.5958) or Phil Leiber (pleiber@caiso.com, 916.351.2168).

Client Relations Communications.
CRCommunications@caiso.com <mailto:CRCommunications@caiso.com>

California Independent
System Operator

Proposed Agenda
2004 GMC Stakeholder Process
Friday, April 11, 2003
10:00 a.m. to 3:00 a.m.
Conference Call-in #1-888-788-6681
Passcode: 921065

1. Introductions/roll call
2. CPUC/EOB update
3. Discussion of SCE rate proposal
4. 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

Created by: Ben Arikawa CAISO LSUPDT: 04/07/03

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CALIFORNIA ISO

California Independent
System Operator

California ISO

Rate Structure Proposal
For the
2004 GMC Rate Structure Project

Project Co-Leads:
Phil Leiber
Debi Le Vine

April 9, 2003

California ISO White Paper on Rate Structure Proposal
As of April 9, 2003

1.0 Introduction

This document and its attachments detail the California Independent System Operator's alternative rate structure proposal as part of the 2004 GMC Rate Structure Project to redesign the structure of its Grid Management Charge (GMC) in accordance with the Initial Decision in ER 01-313-000, *et. al.* and the Settlement Agreement in ER 02-250-000, *et. al.*. They also serve to describe and record the efforts of the California Independent System Operator (California ISO) in developing the proposal.

In developing this proposal, the California ISO and participants reviewed the rate structures of other North American Independent System Operators, FERC ratemaking standards and traditional and marginal cost ratemaking methodologies. In addition, the California ISO worked with participants to review the California ISO's current GMC structure and cost accounting methods and to develop a comprehensive listing of California ISO activities. The California ISO and participants also worked together to develop a list of potential billing determinants for use by any party in developing their own proposal.

The California ISO adopted, where possible, reasonable and appropriate concepts put forth in other parties' rate proposals. The California ISO also took note of the imperatives of the Initial Decision to unbundle California ISO rates, consider demand charges, and to look at alternative methods of cost assignment of certain cost centers.

The California ISO also kept in mind the following criteria from the 2004 GMC Rate Structure Project Charter:

- Develop a rate structure that meets the FERC "just and reasonable" standard, and appropriately allocates ISO costs among the ISO's users;
- Develop a rate structure based on the principle of cost causation, which charges customers for the cost of services that they use/cause;
- Design a rate structure that is easy to administer (including reasonably cost effective, and benefits of change should outweigh the costs) and understandable;
- Develop a rate structure that does not result in unmanageable adverse operational impacts;
- Develop a rate structure that is arrived at through an open and balanced stakeholder process;
- Recover approved ISO costs in a stable, low risk manner without excess volatility;
- Have the new rate structure filed with FERC by November 1, 2003, so that it can be effective January 1, 2004; and,
- Meet the terms of the 2002 GMC Settlement Agreement, which set forth issues to be covered in this 2004 GMC Stakeholder Process.[1]

[1] **2004 GMC Rate Structure Project, a Stakeholder Process**, (project charter) page 2.

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California ISO White Paper on Rate Structure Proposal
As of April 9, 2003

2. Summary of Proposal

Table 1
Summary of the California ISO Rate Proposal
Functionalization and Billing Determinants

Function	Reliability Services		Market Services			Customer Services
Sub-Function	Core Reliability Services	Energy and Transmission Services	Forward Scheduling	Congestion Management	Market Usage and Services	
Billing Determinant	Gross non-coincident peak demand MW	(1) Net Control Area Load plus exports and (2) absolute value of net uninstructed deviations by settlement interval MWh	Final HA schedules submitted, no charge for changes to DA schedules	Net Scheduled Interzonal load (flows) MWh	Purchases and sales of Ancillary Services, instructed energy and absolute value of net uninstructed deviations by settlement interval MWh	(1) Fixed monthly charge per customer and (2)MWh of billable volume on Final Settlement Statement

The table above summarizes the functionalization aspect of the California ISO rate proposal. The Grid Management Charge would consist of three functions. Two of the functions would be sub-functionalized. These functions, with their associated sub-functions are:

1. Reliability Services
    a. Core Reliability Services
    b. Energy and Transmission Services
2. Market Services
    a. Forward Scheduling
    b. Congestion Management
    c. Market Usage and Services
3. Customer Services

These are described more fully below.

2.1 Reliability Services

Under Reliability Services, the California ISO provides safe, reliable operation and maintenance of the Control Area, and provides for transmission expansion, coordination with neighboring Control Areas, management of transmission flows and compliance with regional and national reliability standards.

The following is a partial listing of activities in Reliability Services (a more complete list is in Appendix A):

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- 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

Portions or all of the following systems can be attributed to Reliability Services:

- Energy Management System (EMS)
- Bill's Interchange Transaction Management System (BITS)
- Out-of-Sequence and Out-of-Market Settlements Information System (OSMOSIS)
- Global Reliability Resource Management Application (GRMMA)
- Automated Dispatch System (ADS)
- Scheduling Logging for the ISO of California (SLIC)
- Generator Communication Project (GCP)
- Electronic Tagging (ETAG)

The Reliability Services function consists of two sub-functions, Core Reliability Services and Energy and Transmission Services.

2.1.1 Core Reliability Services

The California ISO provides a basic level of reliable operation of a Control Area surrounded by other control areas and achieving minimal disruptions to system operation. In this sub-function, 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). 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. However, only a basic level of activity is contained in this service. The level of activity does not represent fully functioning operations for a robust Control Area in which there are outages and growth as new generation and transmission projects are developed.

These services must be constantly available in order for the Control Area to operate reliably and must reflect the fact that the Control Area is interconnected with and interacting with other Control Areas and in compliance with all regulatory mandates placed on it.

Included in the costs of these services are the costs of systems applications necessary to operate the Control Area.

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The charge to recover the costs of this service would be assessed on the gross non-coincident peak (NCP) demand of Scheduling Coordinators (SCs) on a monthly basis. Gross NCP demand would include the behind the meter NCP of Qualifying Facilities (QFs) adjusted by a diversity factor.

2.1.2 Energy and Transmission Services

The California ISO provides for the safe, reliable operation of the Control Area assuming everyday (normal and extraordinary) operational requirements in which outages and disruptions (such as weather-related incidents) occur . This is the scalable portion of Reliability Services that is necessary to respond to the everyday occurrence of system activity.

The level of activity is a function of the intensity of use of the transmission system within the Control Area and the occurrence of system outages and disruptions (e.g., weather-related incidents). This includes the services for simultaneously managing energy imbalances and transmission flows beyond those in a steady state Control Area.

For example, grid planning requires more resources in a control area that has growing load and significant need for new transmission and generation facilities. The use of the grid will be more intense if load-serving entities generate only part of their own power and buy part, bringing it to load centers through the grid within the Control Area. A higher level of uninstructed deviations will increase the workload of the California ISO, since actions must be taken to offset these deviations to ensure system-wide balance in real time.

Included in the costs of Energy and Transmission Services are the scalable portion of systems applications and the hardware necessary to operate the Control Area.

In this sub-function, costs are driven by the level of activity within the Control Area.. Thus, they will vary with the volume of flows and the level of net uninstructed deviations within a settlement period. Two volumetric billing determinants will be used: monthly net control area load plus exports (MWh) and the absolute value of net uninstructed deviations by settlement interval (in MWh).

The Energy and Transmission Services charge would not be assessed on behind the meter load.

2.2 Market Services

Under Market Services, the California ISO provides access to its scheduling infrastructure, manages congestion to facilitate transmission flows, operates and maintains California ISO markets for participants, and monitors market performance.

Contained in this function are activities related to the maintenance, monitoring, operation and performance of the forward and Real-Time markets. These activities span many of the activities

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within the ISO's current Congestion Management and Ancillary Services/Real-Time Energy Operations services.

The following is a partial listing of activities in Market Services (a more complete list is found in Appendix A):

- Processing forward market schedules
- Adjusting forward market schedules to mitigate transmission congestion
- Maintaining market information postings
- Operating Real-Time market
- Determining market clearing prices
- Administering primary and secondary Fixed Transmission Rights markets
- Monitoring market performance

Portions or all of the following systems can be attributed to Market Services:

- Scheduling Infrastructure (SI)
- Scheduling Applications (SA)
- Open Access Same-Time Information System (OASIS)
- Automated Dispatch System (ADS)
- Balancing Energy Ex-Post Pricing (BEEP)
- Automated Load Forecasting (ALFS)
- Firm Transmission Rights (FTRs) and Secondary Registration System (SRS)
- Outage Scheduler (OS)
- Existing Transmission Contracts (ETC)
- Congestion Management (CONG)
- Day Ahead Data Analysis Tool (DADAT)
- Hour Ahead Data Analysis Tool (HADAT)

The Market Services function consists three sub-functions, (1) Forward Scheduling, (2) Congestion Management, and (3) Market Usage and Service.

2.2.1 Forward Scheduling

The California ISO provides SCs with the ability to forward schedule energy and Ancillary Services and the 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 California ISO's Scheduling Infrastructure.

The following is a partial listing of activities in Forward Scheduling:

- Processing forward energy schedules, including inter-SC trades

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- Reviewing and verifying schedules

The costs incurred by the California ISO are more closely correlated with the number of schedules than energy volumes, since the basic effort encompasses processing the schedules and bids regardless of the volume within the transactions. The billing determinant will be the number of final hour-ahead schedule templates submitted, not including changes to the DA schedule (so as not to discourage load-following).

2.2.2 Congestion Management

The California 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. Congestion exists when power flowing on a transmission path exceeds the transmission path capacity. Congestion management is conducted by the California ISO during the scheduling process and results in the economic rationing of transmission service in order to prevent congestion. This currently provides for only inter-zonal congestion. Intra-zonal congestion is managed in real-time and thus incorporated in Core Reliability Services.

This service is similar to the CONG service in the current GMC rate design, but is not identical due to the other changes in this proposed rate design. When LMP is implemented, congestion management activities will be functionalized and their associated costs will be assigned to other service categories, eliminating this service category.

The costs of this service would be recovered through an assessment on net scheduled inter-zonal flows (loads).

2.2.3 Market Usage

In this sub-function of Market Services, the California ISO processes supplemental energy and Ancillary Service bids, maintains and controls the Open Access Same-Time Information System (OASIS), monitors market performance, ensures generator compliance with market protocols, and determines market clearing prices. In the future, activities associated with forward energy markets will be included here.

The following is a partial listing of activities in Market Usage and Service (a more complete list is in Appendix A):

- Maintaining market information postings
- Operating Real-Time market
- Determining market clearing prices
- Monitoring market performance

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The costs of this service would be recovered through a per MWh charge on purchases and sales of Ancillary Services, instructed energy and the absolute value of net deviations by Settlement interval by SC ID. Self-provided Ancillary Services would not be assessed this charge.

2.3 Customer Services

Under Customer Services, the California ISO maintains customer account data, provides account information to customers, responds to customer inquiries, calculates market charges, processes settlement statements, resolves customer disputes and provides customer training. This function includes Settlements, Billing, and Metering activities as well as Client Relations. Certain Settlements activities and some Contracts and Special Projects activities are assigned to Core Reliability Services. For example, RMR Settlements is assigned to CRS because its activities are related to the maintenance and provision of RMR services to the Control Area. Similarily, Contracts and Special Projects has a primary role in the Transmission Access Charge and the development of Metered SubSystems.

The following is a partial listing of activities in Customer Services (a more complete list is in Appendix A):

- Determine charges associated with transmission services, forward market schedules, Real-Time balancing market, congestion management and administrative charges
- Maintain and process Settlements data
- Perform Settlement statement re-runs
- Manage and monitor SC credit and collateral
- Collect and validate meter data
- Provide ISO Tariff guidance to Market Participants
- Facilitate resolution of Market Participant issues
- Provide training to Market Participants

Portions or all of the following systems can be attributed to Customer Services:

- Out-of-Sequence, Out-of-Market Settlements Information System (OSMOSIS)
- Balance of Business Systems (BBS)
- Meter Data Acquisition System (MDAS)

Customer Services activities are essential to maintaining any connection between the SCs and the California ISO, regardless of the actual degree of service taken from the California ISO. It can be seen that there are major costs associated with this function. Thus, the mitigation of the bill impacts of assigning these costs on a per customer basis is essential and appropriate. For that reason, the California ISO proposes to recover these costs using both a small fixed monthly charge and a variable charge.

The fixed monthly charge is $500 per SC ID. . The remaining Customer Service costs are recovered from SCs in proportion to the billable quantities by interval on Final Settlement

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statements during a month. The billable quantities do not include quantities associated with manual adjustments performed by ISO Settlements staff.

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3.0 Comparison to Other ISOs/RTOs

Comparisons with other ISOs are difficult as there is no standard for ISO rates. It is also made difficult by the application of the FERC Uniform System of Accounts that were created for application to traditional integrated electric utilities. Nonetheless, in the following we attempt to make some high level comparisons between the California ISO's proposed new rate structure and that of other ISOs/RTOs. These comparisons are shown in Appendix B, in which we compare ISO functions and the method of recovery.

3.1 Reliability Services

Of the five other ISOs (ISO-NE, NYISO, PJM, ERCOT and MISO), only ISO-NE and PJM have "Reliability" functions. ISO-NE's Schedule 3, Reliability Administration, appears to be similar to the California ISO's proposed Reliability Services function. ISO-NE's billing determinant is non-coincident peak demand.

PJM's reliability functions are Schedule 9-1, Control Area, Schedule 9-5, Regulation and Frequency Response, and Schedule 9-7, Capacity and Resource Obligation Management. Schedules 9-1 and 9-5 are recovered through MWh assessments. Schedule 9-1 is recovered through an assessment on point-to-point and network integration services flows in MWhs. Schedule 9-5 is recovered through an assessment on PJM regulation and scheduled regulation, including self-scheduled regulation. Schedule 9-7 is allocated to PJM East and PJM West by their relative non-coincident peaks. Within each region, the cost is recovered by an assessment on resource obligations in MW-days.

3.2 Market Services

Of the other ISOs/RTOs, only ISO-NE and PJM have separate market functions. The market functions of the ISO-NE can be found in Schedule 1-Scheduling, System Control and Dispatch and Schedule 2-Energy Administration. Schedule 1 costs are recovered through an assessment on "monthly Network load in kWs plus the highest amount of reserved capacity of point-to-point transmission plus the highest amount of authorized use." Schedule 2 costs are recovered by assessments on Transaction Units (bilateral contract block hours plus generator block hours plus net deviation block hours) and on load and injections (generation). Fifteen percent of the Schedule 2 costs are recovered from Transaction Units and 85 percent from load and injections.

The market functions of PJM can be found in Schedule 9-4-Market Support, and Schedule 9-3-Fixed Transmission Rights. Market Support costs are recovered from generation and load MWhs. Fixed Transmission Rights costs are recovered through a charge on FTR MW per hour summed over hours. (Essentially, this converts the FTR MWs to MWhs over the year.)

3.3 Customer Services

None of the other ISOs/RTOs have an explicit, separate Customer Services function. All except the MISO have annual fees. These fees are described in Attachment X. ISO-NE, PJM and

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ERCOT have fixed annual fees varying from $2,000 (ERCOT) to $5,000 (ISO-NE and PJM). The NYISO and the Ontario IMO have tiered fees that vary by the amount of load an entity has. The NYISO has a $5,000 fee for all other companies that do not have load.

3.4 Startup Costs

Only the NYISO has explicit recovery of start-up costs. For 2003, the monthly amount recovered is $1,095,881. This amount is assessed equally to customers receiving transmission services under the Open Access Transmission Tariff (OATT) and to customers receiving Location Based Marginal Pricing (LBMP) market services. The current rate for those receiving service under the OATT is $0.046223 per MWh, and the current rate for those receiving LBMP service is $0.047346 per MWh.

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4.0 Cost Assignment Process

The process of identifying and assigning costs to functions and sub-functions was an iterative one. As the California ISO proposal developed, the California ISO's consultants, Barkovich and Yap, Inc., reviewed the current method of cost assignment using the Budget Tool and the resulting structure in the Cost Allocation Matrix (CAM). They then laid out a process in which directors and managers of directly assignable cost centers were asked to assign costs to the California ISO's proposed functions and sub-functions, ultimately to provide data for the ISO's Cost Allocation Matrix

Each set of directors and managers provided three major items. First, they provided a description of their cost center activities to each function or sub-function. Second, they assigned their personnel to the function or sub-function. Finally, they provided a justification of their personnel assignments. The results were tabulated in worksheets, which form the basis for the direct personnel assignments in the CAM.

Barkovich and Yap worked directly with most of the directors and managers, querying results, asking for clarifications, and compiling results. In most cases several meetings and conference calls were required before personnel assignments were completed.

For those cost centers that were not directly assignable, several different methods of assignment were used. The main methods were proportional to:

- Supervised cost center assignments;
- Departmental cost center assignments;
- Total directly assigned operating costs; or
- Total operating cost assignments.

The cost assignment of capital expenditures followed a method similar to that done for cost centers. Whenever possible, capital expenditures were directly assigned. This assignment was done in an iterative process by the directors and managers of the cost centers that utilized the systems . For those capital expenditures that could not be directly assigned, one of the methods in the list above was used.

The results of the cost assignments were linked to the CAM to create the revenue requirements for each function or sub-function. The resulting assignments are shown in the table below:

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California ISO White Paper on Rate Structure Proposal
As of April 9, 2003

Table 2 Revenue Requirements by Function	
Reliability Services	
Core Reliability Services	$ 93,544,836
Energy and Transmission Services	$ 38,337,665
Total Reliability Services	$ 131,882,501
Market Services	
Forward Scheduling	$ 19,039,848
Congestion Management	$ 10,017,448
Market Usage	$ 28,775,078
Total Market Services	$ 57,832,374
Customer Service	$ 47,885,496
Total Revenue Requirement after application of reserve	$ 237,600,371
Revenue requirements shown are based on 2003 Budget information. Cost assignments are preliminary. Further refinement may cause these assignments to change, and allocations will vary as a result of differing costs in the 2004 revenue requirement.	

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5.0 Billing Determinants For Each Service

The California ISO and participants identified a number of potential billing determinants for use by participants and the California ISO early in the Project. This was done to allow the California ISO to begin collection of data and to prevent a lack of data from impeding progress on consideration of alternative rate designs. These billing determinants are listed in:

http://www.caiso.com/docs/09003a6080/1e/f7/09003a60801ef7fb.pdf.

As the California ISO proposal developed and the rate functions crystallized, we analyzed the various potential billing determinants for their suitability for use. This suitability analysis looked at two factors. We preliminarily determined if the billing determinant was causally related to the function for which it was to be used. Then we considered the billing determinant's potential stability, impact on operations and market participant behavior, and its availability in the Settlements system.

Based on this assessment, the California ISO determined that looking beyond the initial list of potential billing determinants was necessary. We found that certain transaction data were suitable for use as a billing determinant. This transaction data is discussed below.

5.1 Core Reliability Services

Core Reliability Services are the basic services needed to manage the Control Area reliably and safely. The billing determinant for this function should be reflective of the costs of maintaining operational control at all times of the day and seasons of the year, as well as the stress that entities place on the transmission system. The billing determinant selected is monthly non-coincident peak (NCP) *demand* on a gross basis. An entity's NCP demand reflects the burden that the entity places on the operation of the transmission system.

Staff rejected use of an entity's coincident peak (CP) demand as the billing determinant. The coincident peak demand would not reflect the burden on system operation of entities whose peaks are not coincident with the system peak. Core Reliability Services must be provided at all times of the day, even to entities that have NCP demand occurring in the middle of the night.

For a portion of gross NCP demand, behind the meter municipal and Qualifying Facilities' load, the California ISO has no direct data. We do have aggregated QF capacity data from the utility reports to the CPUC[2] to which we could apply a diversity factor. The diversity factor accounts for the probability that the sum of the aggregated connected load of the QFs at any time is less than the sum of NCPs of QFs as a class. Put another way, given that QFs are operating differently, it is extremely unlikely that all QFs will peak at the same time. Treating QFs in this manner provides consistent treatment with that of the load of diversified utilities.

[2] For PG&E, this report is entitled "Cogeneration and Small Power Production Semi-Annual Report." For SCE, the report is entitled Qualifying Facilities Semi-Annual Status Report to the California Public Utilities Commission."

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At this time, we are still discussing how to account for the behind the meter load of other entities.

5.2 Energy and Transmission Services

Contained within Energy and Transmission Services is the scalable portion of Reliability Services. Scalability implies an increasing relationship with flows, outages and disturbances within the Control Area. The costs of managing the Control Area will be higher to the extent that total flows increase. They will also be higher to the extent that entities cause inadvertent flows that must be managed in real time. The billing determinants selected by the California ISO are the monthly net Control Area load plus exports and the absolute value of net uninstructed deviations by Settlement interval. The first billing determinant represents total flows and the second represents inadvertent flows on the transmission grid.

The absolute value of net uninstructed deviations by Settlement interval is calculated as the absolute value of the difference between instructed energy and actual energy delivered net of changes in load. Allowing netting for changes in load permits load following (matching changes in generation to changes in load), which reduces inadvertent flows on the transmission grid.

5.3 Forward Scheduling

Forward Scheduling contains the activities associated with accepting, processing, and validating Day-Ahead and Hour-Ahead schedules. A schedule in this context is a template (import, export, load, generation, inter-SC trade, or Ancillary Service) submitted to the Scheduling Infrastructure. The costs in this sub-function relate to providing the infrastructure and to processing schedules.

The billing determinant selected by the California ISO for Forward Scheduling is the number of final Hour-Ahead schedules submitted. Only final Hour-Ahead schedules are assessed this charge. In order not to discourage SCs from modifying their Day-Ahead schedules due to better information, any changes from Day-Ahead schedules that roll over to the Hour Ahead will not be assessed an additional charge.

5.4 Congestion Management

Congestion Management contains the activities associated with mitigating scheduled transmission flows across Inter-zonal boundaries. To the extent flows increase across zonal boundaries, the California ISO incurs costs to monitor and potentially mitigate Inter-zonal congestion.

The billing determinant for Congestion Management will be assessed on net Scheduled Inter-zonal flows (load). This is the current billing determinant for the Congestion Management charge. An SC will be assessed this charge on a per MWh basis each time it schedules a flow across an Inter-zonal interface.

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5.5 Market Usage

Market Usage contains the activities associated with processing Supplemental Energy and Ancillary Services, determining the Real-Time Market Clearing Price, maintaining and controlling the OASIS, monitoring market performance, and ensuring generator compliance with market protocols. In the future, activities associated with forward energy markets will be included here.

The costs of Market Usage will be recovered from those SCs that use the Real-Time market (and the forward energy markets in the future) in a charge based on usage of these markets. The billing determinant for Market Usage will be purchases and sales of Ancillary Services, Instructed Energy and the absolute value of net portfolio deviations by Settlement interval.

This differs from the billing determinant of the current Ancillary Services/Real-Time Energy Operations Charge in that the absolute value of **net** portfolio deviations is used rather than the absolute value of **total** deviations. As was mentioned earlier, to the extent an SC accurately load follows, the California ISO need not purchase Imbalance Energy. The use of net portfolio deviations is a specific mitigation not to discourage load following.

5.6 Customer Services

Customer Services contains most Settlements, Billing, Metering, and Client Relations activities. Customer Services costs are a function of the interaction of the customer and the California ISO. As many of these costs are fixed in nature, such as the requirements for settlements, billing, and processing meter data, cost recovery through a fixed charge per customer may be appropriate. There are variations in the complexity of these interactions between the California ISO and its numerous customers, which militate against recovering these costs solely through a fixed charge.

If the California ISO recovered a major portion of these costs through a single fixed charge per customer, the bill impacts would be significant. As a mitigation measure, the California ISO proposes to recover a portion of Customer Service costs through a $500 per month customer charge per SC ID. The remaining Customer Service costs will be recovered from SCs in proportion to the billable quantities by interval on Final Settlement statements during a month. The billable quantities do not include quantities associated with manual adjustments.

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Table 3
Billing Determinants by Function and Sub-Function

Reliability Services	
Core Reliability Services	534,042 MW-months (NCP demand)*
Energy and Transmission Services	
Load plus exports	242,456,619 MWh
Absolute value of net uninstructed deviation by interval	16,786,796 MWh
Market Services	
Forward Scheduling	12,819,845 schedules
Congestion Management	87,927,387 MWh
Market Usage	38,042,673 MWh
Customer Service	1,653,395,978 MWh

The California ISO collected billing determinants for the twelve-month period September 2001 through August 2002. This was done to facilitate the release of masked SC-specific information to participants under the conditions of providing data at least six months old. The California ISO will review more recent historical data to determine if the collected data is representative.

*The cumulative monthly NCP does not include the NCP of QFs or other entities. These remain to be estimated.

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6.0 Proposed Rates

Based on the process outlined in this paper, the resulting rates are shown in Table 4. We caution that these rates are indicative of the rates that would apply using budgeted costs for the year 2003. Therefore, these can be only illustrative of the actual rates for 2004.

Table 4
Indicative Rates by Function and Sub-Function

Reliability Services	
Core Reliability Services	$175.16 per MW-month of NCP demand*
Energy and Transmission Services	
Load plus exports	$0.13 per MWh
Absolute value of net uninstructed deviation by interval	$0.46 per MWh
Market Services	
Forward Scheduling	$1.49 per schedule submitted
Congestion Management	$0.11 per MWh
Market Usage	$0.76 per MWh
Customer Service	$500 monthly per SC ID, $0.03 per MWh of billable volume on a Final Settlement Statement
*The rate for CRS does not take into account the NCP of QFs or other entities with behind the meter load. These remain to be estimated.	

The functionalization undertaken here reflects an effort to maximize the cost basis of the California ISO's rates. In order to implement this functionalization, it is anticipated that there will be bill impacts that require mitigation. These bill impacts will be studied in depth along with the bill impacts of other proposals. Rates will be adjusted in order to reduce the level of bill impacts to a manageable and reasonable level while preserving the cost basis of the rates to the greatest extent possible.

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7.0 Remaining Issues

As in any undertaking of this magnitude, there are a number of remaining issues that the California ISO and participants must consider. These are:

1. Discussion of commonalities among the California ISO, MID and SCE proposals and the potential for consensus.
2. Estimation of behind the meter load for inclusion in CRS billing determinant.
   Currently, the California ISO does not have information on behind the meter load of Qualifying Facilities and certain municipal utilities.
3. Potential increased use of direct assignments of indirect expenditures
   One participant has requested that the CAISO make an effort to assign more directly the costs that have been assigned indirectly in the past. For this proposal, we have directly assigned costs to the extent possible. There is still some work in this area.
4. Bill impacts
   As we have mentioned, bill impacts will have to be analyzed, not only for the California ISO proposal, but for all proposals before us. We have begun developing the analytical tools to do this and plan to have some analysis ready for the April 28th meeting or conference call.
5. Type and amount of mitigation
   Once we have analyzed bill impacts, some mitigation to reduce the impacts on some customers may be necessary. Mitigation may be necessary regardless of the proposal.
6. Stability of billing determinants through 2003
   At the April 28th meeting, we will provide more recent history on the billing determinants used in all proposals. This will be done to show if there is evidence of a trend or a change in trend from the historical data of September 2001 to August 2002.
7. Transitional mechanisms necessary due to MD02 implementation dates, such as potential for implementation of LMP mid-year in 2004.

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Appendix A
Functionalization of Activity Groupings for ISO Rate Structure (DRAFT)

Function	Sub-Function	Direct Personnel	Activities within proposed Grouping	Indicative Cost Centers (There is some overlap among cost centers)	Applications
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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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	
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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Function	Sub-Function	Direct Personnel	Activities within proposed Grouping	Indicative Cost Centers (There is some overlap among cost centers)	Applications
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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Appendix A
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Function	Sub-Function	Direct Personnel	Activities within proposed Grouping	Indicative Cost Centers (There is some overlap among cost centers)	Applications
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	
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
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	Scheduling Services	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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Functionalization of Activity Groupings for ISO Rate Structure (DRAFT)

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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Appendix A
Functionalization of Activity Groupings for ISO Rate Structure (DRAFT)

Function	Sub-Function	Direct Personnel	Activities within proposed Grouping	Indicative Cost Centers (There is some overlap among cost centers)	Applications
Customer Services		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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Appendix A
Functionalization of Activity Groupings for ISO Rate Structure (DRAFT)

Function	Sub-Function	Direct Personnel	Activities within proposed Grouping	Indicative Cost Centers (There is some overlap among cost centers)	Applications
Customer Services		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	
Customer Services		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		

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Appendix 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)

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	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)

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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

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	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

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Customer Services			
	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)	Customer Services	The ISO maintains customer accounts data and provides account information to clients, responds to customer inquiries, resolves customer disputes.	Monthly fixed charge per customer

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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

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Update on Modesto's GMC Proposal

Laurence D. Kirsch
Laurits R. Christensen Associates, Inc.
www.LRCA.com

CAISO 2004 GMC Rate Design Project Meeting

Folsom, California
April 11, 2003

Exh. No. ISO- 235, Page 1 of 5

Engineering Foundation:
System Operators Minimize Costs
Subject to Constraints

- System Constraints:
  - power balance
  - transmission flow limits
  - voltage limits
- Private Constraints:
  - generator output limits
  - generator ramping limits

Exh. No. ISO- 235, Page 2 of 5

Our Proposed Functions

- Functions that *directly* manage the system constraints:
  - Resolving Energy Imbalances
  - Managing Transmission Flows
- Functions that *indirectly* help manage the system constraints:
  - Administering Markets
  - Scheduling Generators, Loads, and Transmission Facilities

Exh. No. ISO- 235, Page 3 of 5

Our March 7th Cost Assignment

Function	Dollars	Quantity		Rate	
Resolving Energy Imbalances					
uninstructed deviation energy	$20,155,788	16,786,796	MW-intervals	$1.20	/MW-interval
uninstructed deviation demand (12 months)	$20,155,788	54,276	MW-months	$371.36	/MW-month
number of SCs	$2,121,662	876	SC-months	$2,422	/SC-month
	$42,433,238				
Managing Transmission Flows					
power withdrawals	$60,940,789	242,456,619	MWh	$0.25	/MWh
maximum power withdrawals	$60,940,789	625,912	MW-months	$97.36	/MW-month
number of SCs	$6,414,820	876	SC-months	$7,323	/SC-month
	$128,296,398				
Administering Markets					
Trading volumes	$66,870,735	73,374,094	MWh	$0.91	/MWh
Number of SCs	$0	876	SC-months	$0	/SC-month
	$66,870,735				
Totals	$237,600,371				

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Next Steps

- Re-allocate costs among energy, demand, and customer charges
  - to reflect information in the ISO's proposal
- Resolve inconsistencies between billing determinant data of the ISO & MID proposals
- Present rate design to ISO

Exh. No. ISO- 235, Page 5 of 5

CPUC/EOB Modifications to CAISO 2004 GMC Rate Structure Proposal

April 11, 2003

- CPUC/EOB is using the ISO GMC Rate Structure Proposal as a starting point.
- CPUC/EOB is encouraged overall with the ISO's proposal
  - Billing determinants should not be precedential.
  - Review of updated ISO GMC Rate Structure Proposal and implications of billing determinants may require reassessment
  - Billing determinants based on deviations may not be appropriate given today's market/regulatory structure
  - CPUC/EOB proposes some modifications.

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FTR/CRR Charge

- An FTR/CRR charge assessed to SCs with FTRs/CRRs based on MWHs of FTRs/CRRs.
- Costs include: FTR/CRR Auction software, FTR/CRR allocation and simultaneous feasibility studies, Secondary Registration System software, software modifications to accommodate FTRs/CRRs, and associated FTEs.

FTR/CRR Charge (cont)

- Each hour that FTRs/CRRs are available on a path, they are charged a fee calculated from total annual MWhs of FTRs/CRRs and total expected annual costs.
- Currently, the ISO uses a 99.5% availability requirement for the FTR auction. (99.5% of 8,760 hours in a year equals 8,716 hours of availability.)
- ISO determines the number of MWs of FTRs to auction for each path.
- Total annual MWHs of FTRs =

  MWs of FTRs auctioned x 8,716 hours.

FTR/CRR Charge (cont)

- With Obligation CRRs and LMP, the costs and quantity of MWhs of CRRs per year could change substantially.
- ISO has selected a vendor for the CRR software, but no contract has been signed so the cost for this is still confidential.
- Number of CRRs sold depends on simultaneous feasibility of CRR bids made by auction participants.

ETC Charge

- ETC charge assessed to entities with ETCs.
- Costs include ETC software, FTEs to administer & implement ETCs, ETC settlements, etc.
- Options on billing determinants for ETC fee:
  - ETC rights are scheduled by 16 SCs.
  - ETC rights are represented by over 120 active Contract Reference Numbers (CRNs).
  - These could also be weighted by ETC MWs; total MW value of ETC rights is approximately 26,500 MW (total of bi-lateral rights).

Transaction Unit Billing Determinant for Market Usage and Services

- Additional Transaction Unit billing determinant for Market Usage and Services. NEISO apparently assesses a Transaction Unit billing determinant charge for number of transactions (including self-schedules, inter SC trades, and bids) & a Volumetric billing determinant charge for final schedules of load and resources. All transactions are charged under the Transaction Unit billing determinant -- a very small fee in each market and time frame.
- For discussion – Rationale for potentially charging bids as well as self-schedules and inter SC trades: without an ISO centralized market to bid into, resources and load would have to incur a transactional expense (e.g. making calls to other parties, etc.). There is no assurance that a transaction is executed with these calls; likewise there is no assurance that bids in the ISO's markets will be chosen. However, there is a cost to either method.
- Possibly exempt self-schedules with CRRs/ETCs from being counted in Transaction Units.

California ISO
Rate Structure Proposal
April 11, 2003
2004 GMC Rate Structure Project
(revised)

Phil Leiber/Ben T. Arikawa

pleiber@caiso.com, barikawa@caiso.com

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Exh. No. ISO- 237, Page 1 of 25

Topics

- Purpose
- Internal Process
- Functions
- Billing Determinants
- Rates
- Remaining Issues

Purpose

- Develop a rate structure that:
  - Appropriately assigns California ISO costs
  - Minimizes/avoids adverse operational impacts
  - Is relatively easy to administer and is understandable
  - Recovers costs in a stable, low risk manner
  - Meets terms of Initial Decision and 2002 GMC Settlement
- Not a final California ISO determination
  - Open to discussion, changes to structure or concerns welcome and mitigation of bill impacts possible

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Internal Process

- Functionalization
  - Internal discussions (included B&Y)
  - Proposed functionalization
  - Internal ISO feedback
  - Revised functionalization several times

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Internal Process (cont.)

- Cost Assignment Process
  - Interviews and discussions with cost center directors/managers
  - ISO and B&Y reviewed assignment worksheets
  - Questions back to directors/managers
  - Clarifications in response
  - Capital cost assignment followed worksheet assignments (in many cases)

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Internal Process (cont.)

- Cost Allocation Matrix
  - General cleanup
  - Incorporated capital assignments
  - Added extensive notes/documentation

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Functions

- Reliability Services
  - Core Reliability Services
  - Energy Transmission Services
- Market Services
  - Forward Scheduling
  - Congestion Management
  - Market Usage
- Customer Service

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Reliability Services

- ISO provides:
  - Safe, reliable operation of the Control Area
  - Transmission expansion (planning)
  - Coordination with neighboring Control Areas
  - Management of transmission flows
  - Compliance with regional and national reliability standards

Core Reliability Services

- Includes basic level of Reliability Services
- Does not include activities/costs associated with increasing use of transmission grid
- Includes activities/costs of compliance with regulatory agencies and standards
- Includes intertie scheduling and checkout activities/costs and reliability activities

Energy and Transmission Services

- Includes scalable portion of Reliability Services
- Includes activities/costs that vary according to use of and flows on transmission grid
  - Increase in outage coordination activities
  - Increase in transmission planning
  - Increase in Real-Time operations

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Market Services

- Forward Scheduling
- Congestion Management
- Market Usage

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Forward Scheduling

- Processing and validation of Day-Ahead, Hour-Ahead schedules
- Schedules include:
  - Import
  - Export
  - Load
  - Generation
  - Inter SC trades
  - Ancillary Service (including self-provided schedules)

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Congestion Management

- Managing, mitigating inter-zonal congestion through adjustment bids
- Differences from current Congestion Management service are in numerator
  - Grid operations activities moved to Reliability Services
  - Settlements, Billing, Metering and Client Relations costs moved to Customer Service
  - Less costs associated with support/overhead
- Collapses when zonal distinctions go away

Market Usage

- Maintaining market information postings
- Operating Real-Time markets
- Monitoring market performance
- Determining compliance with ISO market protocols

Customer Services

- Includes Settlement, Billing, Metering and Client Relations
- Determine charges for:
  - Transmission services
  - Market activities
- Issues Settlement Statements
- Interactions with customers
  - Dispute resolution
  - Training
  - Tariff guidance

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Billing Determinants

- Core Reliability Services
  - Providing system support at any time of day, even to entities that have peaks at times other than the system peak.
  - Coincident peak does not capture demands placed on ISO.
  - Monthly non-coincident peak (NCP) demand by SC ID including behind the meter demand

Billing Determinants (cont.)

- Energy and Transmission Services
  - Both scheduled and inadvertent flows impact system operation
  - Net Control Area Load plus exports (allocated 80 % of cost)
  - Monthly sum of the absolute values of net uninstructed deviations (allocated 20 % of cost)

Billing Determinants (cont.)

- Forward Scheduling
  - Activities/costs directly related to the number of schedules processed
  - Number of final Hour-Ahead schedules submitted
    - No charge on Hour-Ahead changes to Day-Ahead schedules

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Billing Determinants (cont.)

- Congestion Management
  - Activities/costs related to managing/mitigating congestion on inter-zonal paths
  - Net scheduled inter-zonal flows (load)
  - Same as current methodology

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Billing Determinants (cont.)

- Market Usage
  - Activities/costs related to market activity
  - Purchases and sales of Ancillary Services
  - Instructed and Supplemental Energy
  - Sum of absolute value of net uninstructed deviations
    - Load following not included

Billing Determinants (cont.)

- Customer Service
  - Mostly fixed costs
  - Single monthly charge overly burdensome
  - ISO proposed
    - $500 monthly per SC ID minimum plus balance of costs recovered through an assessment on billable quantities on Final Settlement Statement

Rates - Revenue Requirement

- Reliability Services
  - Core Reliability Services-$93,544,836
  - Energy Transmission Services
    - Net Control Area Load plus exports - $30,670,132
    - Absolute value of net uninstructed deviation by Settlement interval - $7,667,533
- Market Services
  - Forward Scheduling – $19,039,848
  - Congestion Management - $10,017,448
  - Market Usage - $28,775,078
- Customer Service - $47,885,496

Rates - Billing Determinants

- Reliability Services
  - Core Reliability Services- 534,042 MW-months
  - Energy Transmission Services
    - Net Control Area Load plus exports – 242,456,619 MWh
    - Absolute value of net uninstructed deviation by Settlement interval – 16,506,418 MWh
- Market Services
  - Forward Scheduling – 12,819,845 schedules
  - Congestion Management – 87,927,387 MWh
  - Market Usage - 38,042,673 MWh
- Customer Service - 1,653,395,978 MWh

Rates

- Reliability Services
  - Core Reliability Services-$175/MW-month
  - Energy Transmission Services
    - Net Control Area Load plus exports - $0.13/MWh
    - Absolute value of net uninstructed deviation by Settlement interval - $0.46/MWh
- Market Services
  - Forward Scheduling – $1.49/schedule
  - Congestion Management - $0.11/MWh
  - Market Usage - $0.76/MWh
- Customer Service
  - $500 monthly per SC ID
  - $0.03 per MWh billable volume on Final Settlement Statement

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Remaining Issues

- Opportunity for consensus
- Behind the meter NCP
- Assignment of indirects
- Bill impacts
- Mitigation
- Stability of billing determinants
- Transitional mechanisms

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List of Outstanding Issues

1. More direct assignments of indirect expenditures
   a. Assignment of IT (1441 and 1424)
2. More explanations of billing determinants
3. Contractor headcount by cost center
4. Meshing with MD02
   a. LMP vs CONG
   b. Shifts from real time to day ahead (due to uninstructed deviations penalties, etc.)
5. Impact of MSS and new control areas
6. Update billing determinants with more recent data
7. Recovery of MD02 costs
8. Post-June involvement of 2004 GMC Rate Structure Project participants
9. Fees
   a. CAISO
   b. Other ISOs/RTOs

California Independent
System Operator

Agenda
2004 GMC Stakeholder Process
Friday, April 11, 2003
10:00 a.m. to 3:00 p.m.
California ISO
101 Blue Ravine Road
Folsom, California
Conference Call-in #1-888-788-6681
Passcode: 921065

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

See below for meeting notes.

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Meeting notes:

See list of attendees attached at end of these notes.

The meeting started with Bert Hansen of Edison discussing the status of its proposal. Bert had made progress on quantification of the Edison proposal and expected to have some rates within the next week.

David Cohen asked Bert about the relative impact of Edison's suggested discounted rate for Dispatch Export Service (DDES) charge. According to Bert, a maximum of about 3 million MWhs of exports from Mohave would be eligible for the DDES charge. In dollar terms, this was roughly $1.5 million of Control Area Services costs of which Edison (Mohave) would continue to pay $150,000. The remaining $1.35 million would be costs passed back to other parties. Edison acknowledged that it would pay some portion of this in higher GMC costs on its utility operation.

The ISO offered to assist Edison in determining the dollar impact of the DDES charge.

In response to a question, Bert stated that Mohave exports should not incur Ancillary Services charges as Nevada Power and Salt River Project were responsible for reserves.

Bert stated that Edison would consider a separate charge for DDES in other proposals.

CDWR asked if SCE would consider charging behind the meter load. Bert responded that it would be given use of a diversity factor to adjust behind the meter load.

Bert stated that rates from the Edison proposal should be ready for the April 28th meeting.

The discussion next turned to an update on MID's proposal. Dr. Laurence Kirsch made the presentation for MID. Laurence started by recounting the principles behind the MID proposal. These are detailed in his slides (which are posted on the GMC web page). Laurence also reviewed the cost assignments and allocations from the early March report on the MID rate proposal. At the end of his presentation, he laid out the additional steps necessary to complete the MID proposal. These were (1) re-allocate costs among energy, demand and customer charges, (2) resolve inconsistencies between billing determinant data used by MID and that used by the ISO, and (3) present the rate design to the Governing Board of the California ISO.

In follow-up discussion, Laurence stated that MID would like more disaggregated data on market activity. One specific request was that MID would like to see Ancillary Service capacity separated from energy volumes.

After some clarifying questions concerning the ISO's scheduling charge, Laurence stated that MID would look favorably on a scheduling charge. However, given MID's past experience with

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FERC staff, it had not pursued it. However, if the ISO incurred costs processing schedules, then a scheduling charge could be justified.

David Cohen asked if a scheduling charge were accepted, how would MID re-assign costs to properly reflect this? Laurence responded that the cost assignment process would be easier given their earlier experience working with the ISO.

CDWR asked where congestion management costs would be in MID's proposal. Laurence stated that it would be in the Managing Transmission Flows function. There would be no distinction between intra and inter-zonal congestion.

After MID completed its presentation, the Tony Lam (EOB) and Karen Shea (CPUC) made their presentation. In general, the EOB/CPUC were encouraged by the ISO's proposal. However, they argued that the ISO's choice of billing determinants should not be precedential. For example, this meant that if uninstructed deviations were unstable in the future, the ISO should revisit the use of uninstructed deviations as a billing determinant for Market Usage and Energy and Transmission Services.

There was a discussion of the trend of deviations given the return of control to the investor owned utilities. The ISO committed to update the group on trends in billing determinants at the next meeting.

The EOB/CPUC proposed some modifications to the ISO proposal. First, they argued that the ISO should develop an FTR/CRR charge recovered on FTR/CRR MWhs. The EOB/CPUC proposed that the ISO convert the FTR capacity in MWs to energy in MWhs. The ISO had been considering a separate FTR charge, but had not yet fully discussed the idea internally. The ISO concept was to charge a fee for participating in the auction, not to convert the FTR MWs to MWhs and charge a volumetric fee. Also, the ISO expressed some concern that such a measure would not be trackable and such data did not exist in its Settlements database.

The EOB/CPUC proposed that the ISO develop a separate ETC charge to assess entities with ETCs. The ETC charge would be assigned the fully loaded costs of ETC software, direct and indirect personnel and overhead. They offered three different billing determinants for recovery of ETC costs. These were (1) assessment on the 16 SCs with ETC rights, (2) assessment on 120 Contract Reference Numbers, and (3) weighting by ETC MWs.

There was a discussion of the difficulty of correctly identifying ETC costs, the ultimate amount of those costs, of correctly assessing the costs on the proper party and the ability of those parties to pass through the costs to the holder of the contract. The EOB/CPUC appeared to believe that these costs could be directly assessed to the responsible parties.

David Cohen requested that the ISO update the spreadsheet that showed the ETC functionality being built into MD02 software to correctly reflect the definition of ETCs from the ISO Tariff.

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Tony brought out the final point in the EOB/CPUC presentation. This was that the ISO should consider charging for transactions as the ISO-NE was doing. The ISO pointed out that the current ISO proposal did charge for transactions in the Scheduling charge. Also, there was a brief discussion of how the ISO-NE assessed a charge on transactions.

After the lunch break, the ISO began its presentation. Phil Leiber started by describing the internal process that the ISO undertook to develop its proposal. There was some discussion about whether the ISO staff working on GMC had vetted the proposal before other staff and the ISO officers. Phil stated that the officers had been kept fully apprised of the status of the ISO proposal.

At the end of Phil's presentation, Ben Arikawa began describing the ISO proposal. Barbara Barkovich and Catherine Yap, who fielded the majority of the questions, assisted him. The initial discussion centered on the development of the split between Core Reliability Services (CRS) and Energy and Transmission Services. The ISO developed the CRS concept from the hypothetical of a Control Area similar in geography to the ISO Control Area with a similar number of interconnections, transmission lines and generators. Directors and managers were asked to assign costs using this hypothetical.

There were many questions concerning how this split was done and whether this was done consistently. There were also questions on whether the split represented the difference between fixed and variable costs.

The discussion next shifted to the Forward Scheduling sub-function of Market Services. David Cohen asked if other ISOs had scheduling charges. Richard Buckingham (PG&E) asked if the ISO had considered the price elasticity effect of charging for a service that it previously had not. There were addition questions concerning the implementation of the Scheduling charge: would it be charged separately for all Hour-Ahead schedules or was it possible to submit several days worth of schedules and be charged only once. The ISO committed to have examples at the next meeting.

The discussion of the "new" Congestion Management sub-function was next. The ISO proposed to retain a Congestion Management service in response to suggestions at the February 19, 2003 meeting that it would be improper to fold the costs of this service into other functions.

The proposed Congestion Management sub-function is not identical to the current Congestion Management service. The ISO identified various differences in cost assignments between the current Congestion Management function and the proposed Congestion Management sub-function. The differences included assignment of some costs to Reliability Services and Customer Services functions, along with their associated indirects, overheads, and capital.

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The proposed Congestion Management service would be retained until LMP became effective sometime in 2004 or 2005. At that time, the costs of managing congestion might be folded into the Reliability Services function.

There was discussion of the Customer Services function. Some participants had questions regarding the amount of costs in this function and the billing determinant used. The ISO committed to providing examples of how these costs would be recovered.

Near the end of the meeting, there was some additional discussion of the use of NCP as the billing determinant for CRS. CDWR asked if the proper billing determinant was to assess a charge on connected transmission facilities. David Cohen asked if the ISO had thought about how entities might shift usage in response to the billing on NCP. The ISO had not.

David Cohen requested that the ISO provide a diagram showing the ISO's software systems and their integration. The ISO said that this will be provided under the Confidentiality Agreement and Non-Disclosure Certificate.

The next meeting was scheduled for April 28, 2003, 10 am to 3 pm, at the ISO in Folsom. Topics to be discussed may include SC specific billing impacts, stability of billing determinants through the first part of 2003, potential common elements of rate proposals, and potential mitigation of billing impacts.

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List of Participants

Last Name	First	Company	Telephone	E-mail Address
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Arikawa	Ben	ISO	(916) 608-5958	barikawa@caiso.com
Barkovich	Barbara	Barkovich and Yap		
Brommer	Mike	TID	(209) 883-8320	mtbrommer@tid.org
Buckingham	Richard	PG&E	415-973-1717	rabd@pge.com
Cohen	David	Navigant Consulting	(503) 708-7852	dcohen@navigantconsulting.com
Hansen	Bert	SCE	(626) 302-3649	berton.hansen@sce.com
Kehrein	Carolyn	EMS	(707) 678-9506	cmkehrein@ems-ca.com
Kirsch	Laurence	Christensen Associates	(415) 663-8608	lkirsch@lrca.com
Lam	Tony	EOB	(916) 322-8632	tlam@eob.ca.gov
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McGuffin	Mike	ISO	(916) 608-5753	mmcguffin@caiso.com
Mi	JingChao	CDWR	(916) 653-1095	jmi@water.ca.gov
Morrison	Stephen	ISO	(916) 608-7143	smorrison@caiso.com
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Orbeta	Robert	PG&E		
Pritchard	Jan	MID	(209) 526-7490	janp@mid.org
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Ross	James	CAC	(626) 530-9544	jimross@r-c-s-inc.com
Sandino	David	CDWR		
Shea	Karen	CPUC	(415) 703-5404	kms@cpuc.ca.gov
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Withrow	David	ISO	(916) 608-7134	dwithrow@caiso.com
Yakin	Dale	PG&E	(415) 973-1752	dgy4@pge.com
Yap	Catherine	Barkovich and Yap		

Created by: Ben Arikawa CAISO LSUPDT: 04/22/03

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Information Issues 04-15-03.txt

From: lkirsch@svn.net
Sent: Tuesday, April 15, 2003 1:51 PM
To: BArikawa@caiso.com
Cc: dlevine@caiso.com; PLeiber@caiso.com; janp@mid.org; smn@dwgp.com; rchemphill@lrca.com
Subject: Information Issues

Ben:

Just after last week's meeting, I left Phil with a couple of data questions for which information is needed for finalizing MID's MC rate recommendations. These questions are:

1. What is the annual value of the MW-months of 12NCP net load that should be applied to GMC rate design? In principle, this is the sum, over SCs, of each SC's monthly maximum net loads.

2. What is the annual value for trading volumes, excluding uninstructed deviations? It would be nice to have a breakdown by energy, ancillary service, and FTRs.

I would also like to understand the following:

3. In the ISO's GMC proposal, what is the meaning of the billing determinant for Forward Scheduling? It seems to me that 12 million schedules is a large number of schedules for serving 250 million MWh of final load; so I wonder if the meaning of this billing determinant (or the scheduling process itself) differs from my understanding.

Finally, I have a procedural question:

4. What is the date of the ISO Board meeting at which ISO Staff will present its GMC rate recommendations?

Thanks again.

Laurence

****

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

Information Issues 04-15-03.txt
Please visit our website at WWW.LRCA.COM
****

RE Information Issues 04-15-03.txt

From: Leiber, Phil
Sent: Tuesday, April 15, 2003 2:43 PM
To: 'lkirsch@svn.net'
Cc: Pritchard, Jan; Neal, Sean; rchemphill@lrca.com; Arikawa, Ben; Le Vine, Debi
Subject: RE: Information Issues

Lawrence, et. al--

The June Board meeting is June 26, at which time the GMC rate structur e
issue will be voted on by the Board.

There will also be a status report on the GMC at the May 22 Board meeting.

We'll get back to you shortly on the other issues. We're looking through some issues with respect to the volumes.

Philip Leiber, Treasurer & Director of Financial Planning
California ISO
(916) 351-2168
(916) 351-2259 (fax)

-----Original Message-----
From: lkirsch@svn.net [mailto:lkirsch@svn.net]
Sent: Tuesday, April 15, 2003 1:51 PM
To: Arikawa, Ben
Cc: Le Vine, Debi; Leiber, Phil; Pritchard, Jan; Neal, Sean; rchemphill@lrca.com
Subject: Information Issues

Ben:

Just after last week's meeting, I left Phil with a couple of data questions for which information is needed for finalizing MID's GMC rate recommendations. These questions are:

1. What is the annual value of the MW-months of 12NCP net load that should be applied to GMC rate design? In principle, this is the sum, over SCs, of each SC's monthly maximum net loads.

2. What is the annual value for trading volumes, excluding uninstructed deviations? It would be nice to have a

breakdown by energy, ancillary service, and FTRs.

I would also like to understand the following:

3. In the ISO's GMC proposal, what is the meaning of the billing determinant for Forward Scheduling? It seems to me that 12 million schedules is a large number of schedules for serving 250 million MWh of final load; so I wonder if the meaning of this billing determinant (or the scheduling process itself) differs from my understanding.

Finally, I have a procedural question:

4. What is the date of the ISO Board meeting at which ISO Staff will present its GMC rate recommendations?

Thanks again.

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
****

Attachment 91a SCE GMC Proposal Rates.txt

From: Berton.Hansen@sce.com
Sent: Monday, April 21, 2003 1:10 PM
To: barikawa@caiso.com
Subject: SCE GMC Proposal Rates

Ben:

Attached is a spreadsheet showing my preliminary calculation of the rates
associated with SCE's GMC proposal. The rates are shown on a new worksheet
tab "SCE Rates". Also, I included another spreadsheet summarizing the costs that I have allocated with the logic behind the allocation.

I have not done a separate cost allocation for SCE's proposed DDES rate,
but instead have set that rate equal to 10% of the CAS rate, consisten t
with my proposal to the group a few weeks ago.

(See attached file: SCECostAllocation4-07-03.xls)(See attached file: GMCDirect Assignments4-08-03.xls)

California ISO
Confidential Material

Designated Receipent: Bert Hansen, Southern California Edison
Nature of Data: Cost Allocation Matrix Modified for SCE
Dated: April 7, 2003
Date of Release: April 7, 2003
Intended for the designated recipients only, not to be copied or distributed

Disclaimer Regarding the Attached Data

The data is intended for the designated recipients only and is provided solely for the purpose of furthering discussion and research in the ISO's '2004 Rate Structure Project'. The data, in the form attached, is provided in response to Stakeholders' requests and as such does not necessarily indicate the ISO's concurrence in, or support for, its usefulness in developing a rate methodology. No implications may be drawn regarding the ISO's position on any subject in the Project from either the inclusion or exclusion of any specific data. The ISO does not warrant the completeness or accuracy of the data.

California ISO
Cost Allocation Matrix: FY2003 Budget
Summary Table of Results

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Appendix A

Category	Control Area Operations	Congestion Management	ASREO/MO	Total
Cost Allocation Percentages, Prior to Reserve Credit	57.8%	12.1%	30.1%	100.0%
Revenue Requirement prior to Reserve Credit	$142,073,473	$29,758,602	$74,025,002	$245,857,076
Cost Allocation Percentage, After Reserve Credit	58.0%	11.5%	30.4%	100.0%
Revenue Requirement, After Reserve Credit	$ 137,856,869	$ 27,400,520	$ 72,342,981	$ 237,600,371

FOR DEVELOPMENT AND EVALUATION OF MID PROPOSAL

Control Area Services	Dynamic Dispatch Export Service	Scheduling Generator Loads and Transmission Facilities	Market Operations Service	Real Time Market Operations Service	Total
70.4%	0.0%	6.8%	15.6%	7.1%	100.0%
$ 173,134,471	$ -	$ 16,836,381	$ 38,426,932	$ 17,459,292	245,857,076
70.4%	0.0%	6.8%	15.6%	7.1%	100.0%
167,320,035	-	16,270,959	37,136,426	16,872,951	$ 237,600,371

Attached Worksheets

Summary Cost Allocation Matrix	Appendix C1
Cost Allocation Matrix	Appendix C2
Worksheet for Allocation of Certain Supervisory Departments	Appendix C5

DISCLAIMER

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CALIFORNIA ISO

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SUMMARY COST ALLOCATION MATRIX - 2003 BUDGET

Line#	ISO Dept #	OPERATING COSTS	Amount Salaries	Amount Total	Allocation				Cost Allocated		
					Control Area Services	Congestion Mgmt.	ASREO/MO	Allocation/ Assignment Method	Control Area Services	Congestion Mgmt.	ASREO/MO
1		Gross Operating Costs									
2	1500	Operations - Direct									
3	1521	Grid Planning	$ 2,041,338	$ 2,425,338	100.0%	0.0%	0.0%	Direct Assignment	$2,425,338	$0	$0
4	1542	Outage Coordination	$ 1,580,356	$ 1,780,930	100.0%	0.0%	0.0%	Direct Assignment	$1,780,930	$0	$0
5	1543	Loads and Resources	$ 943,936	$ 1,006,436	100.0%	0.0%	0.0%	Direct Assignment	$1,006,436	$0	$0
6	1544	Real-Time Scheduling	$ 2,578,768	$ 2,680,968	75.0%	15.0%	10.0%	Direct Assignment	$2,010,726	$402,145	$268,097
7	1545	Grid Operations - General	$ 6,844,825	$ 7,167,325	79.6%	10.2%	10.2%	Direct Assignment	$5,702,047	$733,879	$731,399
8	1546	Security Coordination	$ 1,207,891	$ 1,255,891	100.0%	0.0%	0.0%	Direct Assignment	$1,255,891	$0	$0
9	1549	Operations Training	$ 1,919,268	$ 3,064,253	61.7%	24.1%	14.2%	Direct Assignment	$1,890,463	$737,849	$435,942
10	1554	Special Projects Engineering	$ 601,931	$ 860,981	84.2%	-0.1%	15.9%	Direct Assignment	$725,153	($1,118)	$136,945
11	1555	Operations Support Group	$ 974,683	$ 1,025,163	60.6%	21.5%	18.0%	Direct Assignment	$620,880	$220,082	$184,201
12	1558	Transmission Maintenance	$ 1,141,103	$ 1,804,953	98.2%	0.0%	1.8%	Direct Assignment	$1,773,365	$0	$31,588
13	1561	Operations Engineering South	$ 1,034,681	$ 1,240,187	100.0%	0.0%	0.0%	Direct Assignment	$1,240,187	$0	$0
14	1562	Operations Engineering North	$ 1,168,863	$ 1,226,703	100.0%	0.0%	0.0%	Direct Assignment	$1,226,703	$0	$0
15	1563	Coordinated Operations	$ 584,551	$ 677,951	60.0%	10.0%	30.0%	Direct Assignment	$406,771	$67,795	$203,385
16	1565	Pre-Scheduling and Support	$ 1,660,765	$ 1,697,365	73.9%	14.6%	11.5%	Direct Assignment	$1,254,021	$248,406	$194,938
17	1566	Regional Coordination - General	$ 423,012	$ 554,912	83.2%	0.0%	16.8%	Direct Assignment	$461,569	$0	$93,343
18	1559	Operations Application Support	$ 447,958	$ 458,472	78.9%	10.5%	10.6%	Direct Assignment	$361,629	$48,126	$48,717
19	1500	Operations - Indirect									
20	1511	VP Grid Operations - General	$ 365,202	$ 1,011,957	66.4%	18.3%	15.3%	Allocated based on Department Direct Cos	$671,941	$185,061	$154,956
21	1547	Engineering and Maintenance - General	$ 289,222	$ 1,154,222	99.4%	0.0%	0.6%	Allocated based on Supervised Departme	$1,147,315	$0	$6,907
22	1548	OSAT Group - General	$ 182,432	$ 267,932	76.5%	6.5%	17.0%	Allocated based on Supervised Departme	$205,048	$17,342	$45,543
23	1564	Operations Scheduling - General	$ 281,362	$ 322,862	81.9%	10.6%	7.5%	Allocated based on Supervised Departme	$264,489	$34,101	$24,272
24	1700	VP Market Services									
25	1722	Application Support	$ 414,256	$ 510,466	19.0%	7.0%	74.0%	Direct Assignment	$96,796	$35,712	$377,957
26	1723	Tariff and Contract Implementation	$ 667,205	$ 896,883	90.0%	0.0%	10.0%	Direct Assignment	$807,195	$0	$89,688
27	1724	BBS - PSS	$ 942,333	$ 1,148,361	16.8%	7.7%	75.5%	Direct Assignment	$193,228	$88,510	$866,623
28	1725	BBS - FSS	$ 1,037,777	$ 1,280,321	15.6%	7.4%	77.0%	Direct Assignment	$200,292	$94,667	$985,362
29	1731	Contracts and Special Projects	$ 1,153,955	$ 1,439,963	76.6%	2.4%	21.0%	Direct Assignment	$1,102,613	$34,935	$302,416
30	1741	Client Relations	$ 2,054,540	$ 2,299,956	37.8%	9.5%	52.7%	Direct Assignment	$869,540	$218,093	$1,212,323
31	1752	Manager of Markets	$ 2,156,353	$ 2,355,353	28.8%	30.0%	41.2%	Direct Assignment	$677,679	$706,606	$971,068
32	1753	Market Engineering	$ 1,680,883	$ 2,061,799	31.7%	28.1%	40.2%	Direct Assignment	$653,659	$578,688	$829,452
33	1755	Business Solutions	$ 739,166	$ 942,745	25.2%	10.5%	64.3%	Direct Assignment	$237,599	$98,675	$606,471
34	1756	Market Quality - General	$ 1,940,408	$ 2,102,565	37.1%	33.1%	29.8%	Direct Assignment	$780,139	$695,886	$626,540
35	1757	Market Integration	$ 587,361	$ 835,895	25.1%	30.0%	44.9%	Direct Assignment	$210,108	$250,769	$375,019
36	1700	Market Services - Indirect									
37	1711	VP Market Services - General	$ 394,287	$ 248,117	36.9%	17.9%	45.2%	Allocated based on Department Direct Cos	$91,454	$44,484	$112,179
38	1721	Billing and Settlements-General	$ 347,911	$ 353,911	33.8%	5.7%	60.5%	Allocated based on Supervised Departme	$119,708	$20,195	$214,008
39	1751	Market Operations - General	$ 331,747	$ 959,968	20.0%	30.0%	50.0%	Allocated based on Supervised Departme	$191,994	$287,990	$479,984
40	1400	Information Services - Direct									
41	1424	Asset Management	$ 845,319	$ 21,742,188	67.3%	6.9%	25.9%	Direct Assignment	$14,627,029	$1,493,935	$5,621,224
42	1441	Outsourced Contracts	$ 159,466	$ 29,683,478	60.1%	10.7%	29.2%	Allocated based on Labor Dollar Ratios-Sp	$17,831,873	$3,174,793	$8,676,812
43	1461	Control Systems	$ 2,186,977	$ 2,321,654	100.0%	0.0%	0.0%	Direct Assignment	$2,321,654	$0	$0
44	1462	Field Data Acquisition System (FDAS)	$ 1,805,783	$ 2,508,556	29.9%	8.2%	61.9%	Direct Assignment	$749,148	$205,422	$1,553,986
45	1467	Settlement Systems Services	$ 980,615	$ 1,064,350	15.0%	7.0%	78.0%	Direct Assignment	$159,653	$74,505	$830,193
46	1400	VP Information Services Indirect									
47	1411	Chief Information Officer- General	$ 391,143	$ 212,246	62.3%	8.6%	29.1%	Allocated based on Department Direct Cos	$132,151	$18,324	$61,771
48	1422	Corporate & Enterprise Applications - General	$ 233,320	$ 248,320	61.7%	10.0%	28.3%	Allocated based on Supervised Departme	$153,231	$24,743	$70,346
49	1431	End User Support	$ 491,206	$ 6,565,001	63.1%	10.4%	26.5%	Allocated based on Direct Operating Costs	$4,140,334	$682,660	$1,742,007
50	1432	Computer Operations - General	$ 403,068	$ 430,975	60.7%	10.0%	29.2%	Allocated based on Supervised Departme	$261,804	$43,166	$126,005
51	1433	Network Operations	$ 1,549,597	$ 1,629,905	63.1%	10.4%	26.5%	Allocated based on Labor Dollar Ratios-Sp	$1,027,928	$169,485	$432,491
52	1442	Production Support	$ 2,440,565	$ 2,581,165	56.2%	9.3%	34.5%	Allocated based on Direct Operating Costs	$1,450,351	$239,135	$891,679
53	1451	Information Security	$ 1,038,281	$ 1,509,500	63.1%	10.4%	26.5%	Allocated based on Direct Operating Costs	$951,993	$156,965	$400,542
54	1463	Operations Applications - General	$ 292,237	$ 323,539	74.3%	1.6%	24.1%	Allocated based on Supervised Departme	$240,496	$5,081	$77,963
55	1466	Enterprise Applications	$ 764,123	$ 816,499	61.8%	9.4%	28.9%	Allocated based on Direct Operating Costs	$504,271	$76,413	$235,815
56	1468	Corporate Application Support	$ 1,188,702	$ 1,333,287	60.6%	10.0%	29.4%	Allocated based on Direct Operating Costs	$807,950	$133,215	$392,122
57	1469	Analytical and Reporting	$ 984,106	$ 1,055,106	63.1%	10.4%	26.5%	Allocated based on Direct Operating Costs	$665,421	$109,715	$279,970
58	1471	IT Planning	$ 628,349	$ 770,116	63.1%	10.4%	26.5%	Allocated based on Direct Operating Costs	$485,687	$80,080	$204,348
59	1481	Markets and Scheduling	$ 1,267,761	$ 1,520,628	56.2%	9.3%	34.6%	Allocated based on Direct Operating Costs	$854,034	$140,813	$525,781
60	1600	Legal - Direct									
61	1641	Market Analysis	$ 1,997,346	$ 3,053,880	22.6%	19.3%	58.1%	Direct Assignment	$688,824	$589,477	$1,775,579
62	1642	Market Surveillance Committee	$ -	$ 640,750	9.2%	25.0%	65.8%	Direct Assignment	$59,075	$160,188	$421,488
63	1661	Compliance - General	$ 1,150,095	$ 1,456,895	81.8%	5.5%	12.7%	Direct Assignment	$1,191,963	$80,118	$184,814
64	1662	Compliance - Audits	$ 357,191	$ 416,191	83.7%	4.8%	11.5%	Direct Assignment	$348,359	$19,916	$47,916
65	1300	Finance - Corporate Indirect									
66	1311	CFO - General	$ 420,090	$ 424,204	60.9%	10.7%	28.4%	Allocated based on Supervised Departme	$258,449	$45,232	$120,523

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SUMMARY COST ALLOCATION MATRIX - 2003 BUDGET

Line#	ISO Dept #	OPERATING COSTS	Amount Salaries	Amount Total	Allocation				Cost Allocated		
					Control Area Services	Congestion Mgmt.	ASREO/MO	Allocation/ Assignment Method	Control Area Services	Congestion Mgmt.	ASREO/MO
67	1321	Accounting	$ 836,830	$ 2,168,530	47.4%	7.8%	44.8%	Allocated based on Direct Operating Costs	$1,027,277	$168,937	$972,316
68	1331	Financial Planning and Treasury	$ 714,782	$ 2,511,009	59.8%	10.3%	29.9%	Allocated based on Direct Operating Costs	$1,501,215	$258,804	$750,990
69	1351	Facilities	$ 641,351	$ 5,812,962	63.6%	10.9%	25.5%	Allocated based on Labor Dollar Ratios	$3,698,575	$634,003	$1,480,384
70	1361	Office Administration	$ 643,601	$ 2,227,171	63.6%	10.9%	25.5%	Allocated based on Labor Dollar Ratios	$1,417,067	$242,911	$567,193
71	1600	Legal - Chief Counsel - Corporate Indirect									
72	1611	VP General Counsel - General	$ 468,583	$ 385,985	57.3%	11.1%	31.6%	Allocated based on Supervised Departme	$221,074	$42,980	$121,931
73	1631	Legal and Regulatory	$ 3,330,071	$ 13,118,010	61.7%	10.1%	28.2%	Allocated based on Direct Operating Costs	$8,097,100	$1,319,917	$3,700,993
74	1800	VP Corporate and Strategic Development - Corporate Indirect									
75	1811	VP Corporate and Strategic Development - Gene	$ 392,226	$ 497,434	63.2%	10.6%	26.3%	Allocated based on Supervised Departme	$314,243	$52,599	$130,592
76	1821	Communications	$ 452,711	$ 865,811	63.6%	10.9%	25.5%	Allocated based on Direct Operating Costs	$550,884	$94,432	$220,496
77	1831	Strategic Development	$ 477,745	$ 693,745	63.6%	10.9%	25.5%	Allocated based on Direct Operating Costs	$441,405	$75,665	$176,676
78	1851	Project Office	$ 583,258	$ 657,758	62.8%	10.3%	26.8%	Allocated based on Direct Operating Costs	$413,297	$67,917	$176,544
79	1861	Regulatory Policy	$ 585,142	$ 1,430,767	62.8%	10.3%	26.8%	Allocated based on Direct Operating Costs	$899,011	$147,735	$384,022
80	1241	MD02-Corporate Indirect									
81	1241	MD02	$ 882,609	$ 909,609	32.0%	33.0%	35.0%	Direct Assignment	$291,075	$300,171	$318,363
82		CEO / Human Resources - Corporate Indirect									
83	1111	CEO - General	$ 744,874	$ 730,899	62.8%	11.1%	26.1%	Allocated based on Labor Dollar Ratios	$459,243	$81,021	$190,636
84	1841	Human Resources	$ 1,166,617	$ 4,794,842	62.8%	11.1%	26.1%	Allocated based on Labor Dollar Ratios	$3,012,722	$531,513	$1,250,607
85	1651	Board of Governors		$ 163,100	62.8%	11.1%	26.1%	Allocated based on Labor Dollar Ratios	$102,480	$18,080	$42,540
86		Salary Adjustments, FY2003		$ 3,341,960	62.4%	10.5%	27.2%		$2,084,220	$349,462	$908,278
87		**Gross Operating Costs**	**$ 74,216,069**	**$ 171,739,129**					**$107,105,467**	**$17,958,404**	**$46,675,258**
88		**Gross Operating Costs %**							62.4%	10.5%	27.2%
89		Other Revenues									
90		Interest Revenues		$ (1,252,400)	62.3%	10.4%	27.2%	Operating Costs	($780,857)	($130,686)	($340,857)
91		SC Application and Training Fees		$ (120,000)	62.3%	10.4%	27.2%	Cost Center 1546	($74,819)	($12,522)	($32,660)
92		WSCC Security Coordination		$ (1,255,891)	100.0%	0.0%	0.0%	Operating Costs	($1,255,891)	#VALUE!	$0
93		**Total Other Revenue**		**$ (2,628,291)**					**($2,111,567)**	#VALUE!	**($373,517)**
94		**Total Other Revenue %**							80.3%	5.4%	14.2%
95		Net Operating Costs									
96		**Net Operating Costs**		**$ 169,110,838**					**$104,993,900**	#VALUE!	**$46,301,742**
97		**Net Operating Costs %**							62.1%	10.5%	27.4%
98		Capital									
99		EMS		$16,470,000	100.0%	0.0%	0.0%	Direct Assignment	$16,470,000	$0	$0
100		SI		$27,102,000	39.0%	20.0%	41.0%	Direct Assignment	$10,569,780	$5,420,400	$11,111,820
101		SA		$31,681,000	35.0%	25.0%	40.0%	Direct Assignment	$11,088,350	$7,920,250	$12,672,400
102		BBS (Billing & Settlements)		$48,173,000	15.0%	7.0%	78.0%	Direct Assignment	$7,225,950	$3,372,110	$37,574,940
103		MDAS (Metering)		$8,166,000	30.0%	8.0%	62.0%	Direct Assignment	$2,449,800	$653,280	$5,062,920
104		RMR-Software		$56,000	100.0%	0.0%	0.0%	Direct Assignment	$56,000	$0	$0
105		Market Anaysis Software		$238,000	0.0%	0.0%	100.0%	Direct Assignment	$0	$0	$238,000
106		Vehicles MDAS/Metering		$96,000	30.0%	8.0%	62.0%	Direct Assignment	$28,800	$7,680	$59,520
107		FERC Study Software		$11,000	25.0%	25.0%	50.0%	Direct Assignment	$2,750	$2,750	$5,500
108		GCP/RIG (Generator Communication with ISO)		$975,000	100.0%	0.0%	0.0%	Direct Assignment	$975,000	$0	$0
109		SRS Software (FTR related)		$1,049,000	10.0%	75.0%	15.0%	Direct Assignment	$104,900	$786,750	$157,350
110		ETC Software		$891,000	100.0%	0.0%	0.0%	Direct Assignment	$891,000	$0	$0
111		FTR Auction software		$17,000	10.0%	75.0%	15.0%	Direct Assignment	$1,700	$12,750	$2,550
112		ACC Upgrades (Communication btw ISO and IOUs)		$1,162,000	100.0%	0.0%	0.0%	Direct Assignment	$1,162,000	$0	$0
113		**Total Infrastructure Direct Assigned Items**		**$136,087,000**					$51,026,030	$18,175,970	$66,885,000
114		Infrastructure - Allocated Items									
115		Issue Management System -Remedy		$692,000	62.1%	10.5%	27.4%	Operating Costs	$429,634	$72,900	$189,466
116		Security System - CUDA		$6,993,000	62.1%	10.5%	27.4%	Operating Costs	$4,341,663	$736,686	$1,914,650
117		Corporate Accounting - Oracle		$2,993,000	62.1%	10.5%	27.4%	Operating Costs	$1,858,229	$315,301	$819,469
118		Document Management System - EDMS		$1,715,000	62.1%	10.5%	27.4%	Operating Costs	$1,064,772	$180,669	$469,559
119		HR System - Imperativ		$136,000	62.1%	10.5%	27.4%	Operating Costs	$84,437	$14,327	$37,236
120		HR System - ABRA		$38,000	62.1%	10.5%	27.4%	Operating Costs	$23,593	$4,003	$10,404
121		System Management and Monitoring - Tivoli		$200,000	62.1%	10.5%	27.4%	Operating Costs	$124,172	$21,069	$54,759
122		Data Warehouse		$1,279,000	62.1%	10.5%	27.4%	Operating Costs	$794,078	$134,738	$350,184
123		Network Software		$630,000	62.1%	10.5%	27.4%	Operating Costs	$391,141	$66,368	$172,491
124		Facilities		$10,566,000	62.8%	11.1%	26.1%	Labor Dollar Ratios	$6,636,761	$1,168,391	$2,760,848
125		Furniture		$5,391,000	62.8%	11.1%	26.1%	Labor Dollar Ratios	$3,386,218	$596,138	$1,408,644
126		Facilities-Office Equipment		$1,330,000	62.8%	11.1%	26.1%	Labor Dollar Ratios	$835,405	$147,072	$347,523
127		Transmission Display Software - TIDS		$139,000	62.1%	10.5%	27.4%	Operating Costs	$86,299	$14,643	$38,058
128		Other software and Enhancements		$3,482,000	62.1%	10.5%	27.4%	Operating Costs	$2,161,829	$366,816	$953,355
129		MCI Contract		$27,040,000	60.1%	10.7%	29.2%	Telecom Dept	$16,243,846	$2,892,060	$7,904,094
130		IBM Contract		$6,816,000	60.7%	10.0%	29.2%	IT Dept	$4,140,503	$682,688	$1,992,809

SUMMARY COST ALLOCATION MATRIX - 2003 BUDGET

Line#	ISO Dept #	OPERATING COSTS	Amount Salaries	Amount Total	Allocation				Cost Allocated		
					Control Area Services	Congestion Mgmt.	ASREO/MO	Allocation/ Assignment Method	Control Area Services	Congestion Mgmt.	ASREO/MO
131		**Total Infrastructure Allocated Items**		**$69,440,000**					$42,602,582	$7,413,869	$19,423,549
132		**Subtotal Infrastructure**		**$205,527,000**					$93,628,612	$25,589,839	$86,308,549
133		**Subtotal Infrastructure %**						Allocation %	45.6%	12.5%	42.0%
134		Startup - Allocated Items							0		
135		Trustee Costs		$5,692,000	45.6%	12.5%	42.0%	Infrastructure subtotal	$2,593,012	$708,702	$2,390,286
136		Interest-Capitalized		$1,261,000	45.6%	12.5%	42.0%	Infrastructure subtotal	$574,453	$157,005	$529,542
137		User Groups		$957,000	45.6%	12.5%	42.0%	Infrastructure subtotal	$435,965	$119,155	$401,880
138		Startup Costs-through 3/31/98		$52,897,000	62.1%	10.5%	27.4%	Operating Costs	$32,841,552	$5,572,502	$14,482,947
139		Working Capital-3 months		$21,692,000	62.1%	10.5%	27.4%	Operating Costs	$13,467,662	$2,285,171	$5,939,166
140		**Total Startup Allocated Items**		**$82,499,000**					$49,912,645	$8,842,534	$23,743,821
141		Other Software and Enhancements									
142		2000 Spending: EMS/MDAS/Participating Load Prog		$1,651,155	91.5%	1.0%	7.5%	Direct Assignment	$1,511,467	$16,016	$123,672
143		2000 Spending: SA/SI/BBS		$4,569,322	22.9%	51.6%	25.4%	Direct Assignment	$1,047,746	$2,359,598	$1,161,979
144		2000 Spending: Other Systems/Vehicles		$1,240,714	12.7%	0.7%	86.6%	Direct Assignment	$157,198	$8,561	$1,074,955
145		2001 Spending: Other Systems		$4,439,568	62.1%	10.5%	27.4%	Operating Costs	$2,756,344	$467,692	$1,215,533
146		2000 Spending: Facilities/Furniture/Office Equipment		$1,473,241	62.8%	11.1%	26.1%	Labor Dollar Ratios	$925,378	$162,911	$384,951
147		**Total Other Software and Enhancements**		**$13,374,000**					$6,398,133	$3,014,778	$3,961,089
148		Total 1998 Bonds									
149		Total 1998 Bonds		**$301,400,000**					$149,939,390	$37,447,152	$114,013,458
150		Total 1998 Bonds %						Allocation %	49.7%	12.4%	37.8%
151		Total 2000 Bonds									
152		Land & Building Costs		$9,300,000	62.8%	11.1%	26.1%	Labor Dollar Ratios	$5,841,556	$1,028,396	$2,430,048
153		2000 Spending:SA/SI/BBS		$15,233,506	49.3%	0.5%	50.1%	Direct Assignment	$7,514,689	$82,261	$7,636,557
154		2000 Spending: EMS/CIM/FDA		$1,435,154	83.1%	1.9%	15.0%	Direct Assignment	$1,191,895	$27,842	$215,417
155		2000 Spending: Other Systems		$4,000,555	62.1%	10.5%	27.4%	Operating Costs	$2,483,779	$421,444	$1,095,333
156		2001 Spending: EMS		$5,286,679	100.0%	0.0%	0.0%	Direct Assignment	$5,286,679	$0	$0
157		2001 Spending: SA/SI/BBS		$844,106	40.1%	0.0%	59.9%	Direct Assignment	$338,824	$0	$505,282
158		Total 2000 Bonds		**$36,100,000**					$22,657,421	$1,559,943	$11,882,636
159		Total 2000 Bonds %						Allocation %	62.8%	4.3%	32.9%
160		Total 1998 and 2000 Bonds									
161		Total 1998 and 2000 Bonds		**$337,500,000**					$172,596,811	$39,007,094	$125,896,094
162		Total 1998 and 2000 Bonds %						Allocation %	51.1%	11.6%	37.3%
163		Total Debt Service									
164		Debt Service - Existing Debt (1998 and 2000 Bonds): Including Re		$54,746,238	51.1%	11.6%	37.3%	1998 & 2000 bonds	$27,997,114	$6,327,383	$20,421,741
165											
166		Total Debt Service Cost		**$54,746,238**					**$27,997,114**	**$6,327,383**	**$20,421,741**
167		Total Debt Service Cost %						Allocation %	51.1%	11.6%	37.3%
168		Cash Funded Cap Ex: 2003 Capital Budget									
169		2003 Budget: Operating Systems		$3,193,000	60.4%	7.9%	31.7%	Direct Assignment	$1,928,253	$253,205	$1,011,542
170		2003 Budget: Furniture/Facilities/Office Equipment		$445,000	62.8%	11.1%	26.1%	Labor Dollar Ratios	$279,515	$49,208	$116,276
171		2003 Budget: Corporate Systems		$3,320,000	62.1%	10.5%	27.4%	Operating Costs	$2,061,250	$349,750	$909,000
		2003 Budget: MD02		$15,042,000	32.0%	33.0%	35.0%	Direct Assignment	$4,813,440	$4,963,860	$5,264,700
172		Total Cash Funded Cap Ex		**$22,000,000**					**$9,082,458**	**$5,616,023**	**$7,301,519**
173		Total Cash Funded Cap Ex%						Allocation %	41.3%	25.5%	33.2%
174		Total Cost of Service - 2003									
175		Gross O&M Costs		$171,739,129	62.1%	10.5%	27.4%		$107,105,467	$17,958,404	$46,675,258
176		Other Costs and Income		($2,628,291)	80.3%	5.4%	14.2%		($2,111,567)	($143,208)	($373,517)
177		Net O&M Costs		$169,110,838	62.4%	10.5%	27.2%		$104,993,900	$17,815,196	$46,301,742
178		Debt Service		$54,746,238	51.1%	11.6%	37.3%		$27,997,114	$6,327,383	$20,421,741
179		Cash Funded Cap Ex		$22,000,000	41.3%	25.5%	33.2%		$9,082,458	$5,616,023	$7,301,519
180		Total Cost of Service: Prior to Op. Reserve		$245,857,076					**$142,073,473**	**$29,758,602**	**$74,025,002**
181		Total Cost of Service %						Allocation % results before Revenue Credit or Deficiency	57.8%	12.1%	30.1%
182		(Revenue Credit)/Shortfall		($8,256,705)					$ (4,216,604)	$ (2,358,081)	$ (1,682,020)
183		Total Cost of Service		$237,600,371					**$137,856,869**	**$27,400,520**	**$72,342,981**
184		Total Cost of Service %						Net Allocation %	58.0%	11.5%	30.4%

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Allocation						Cost Allocated					
Control Area Services	Dynamic Dispatch Export Service	Scheduling Service	Market Operations Service	Real Time Market Operations Service	Allocation/ Assignment Method	Control Area Services	Dynamic Dispatch Export Service	Scheduling Service	Market Operations Service	Real Time Market Operations Service	Cost-Allocation Reasoning
100.0%	0.0%	0.0%	0.0%	0.0%	To Assess	$2,425,338	$0	$0	$0	$0	All CAS
100.0%	0.0%	0.0%	0.0%	0.0%	To Assess	$1,780,930	$0	$0	$0	$0	All CAS
100.0%	0.0%	0.0%	0.0%	0.0%	To Assess	$1,006,436	$0	$0	$0	$0	All CAS
85.0%	0.0%	5.0%	5.0%	5.0%	To Assess	$2,278,823	$0	$134,048	$134,048	$134,048	?????
80.0%	0.0%	0.0%	5.0%	15.0%	To Assess	$5,733,860	$0	$0	$358,366	$1,075,099	?????
100.0%	0.0%	0.0%	0.0%	0.0%	To Assess	$1,255,891	$0	$0	$0	$0	All CAS
65.0%	0.0%	15.0%	15.0%	5.0%	To Assess	$1,991,764	$0	$459,638	$459,638	$153,213	?????
90.0%	0.0%	0.0%	10.0%	0.0%	To Assess	$774,883	$0	$0	$86,098	$0	?????
100.0%	0.0%	0.0%	0.0%	0.0%	To Assess	$1,025,163	$0	$0	$0	$0	?????
100.0%	0.0%	0.0%	0.0%	0.0%	To Assess	$1,804,953	$0	$0	$0	$0	All CAS
100.0%	0.0%	0.0%	0.0%	0.0%	To Assess	$1,240,187	$0	$0	$0	$0	All CAS
100.0%	0.0%	0.0%	0.0%	0.0%	To Assess	$1,226,703	$0	$0	$0	$0	All CAS
80.0%	0.0%	0.0%	20.0%	0.0%	To Assess	$542,361	$0	$0	$135,590	$0	?????
90.0%	0.0%	5.0%	5.0%	0.0%	To Assess	$1,527,629	$0	$84,868	$84,868	$0	All Scheduling
100.0%	0.0%	0.0%	0.0%	0.0%	To Assess	$554,912	$0	$0	$0	$0	All CAS
90.0%	0.0%	0.0%	10.0%	0.0%	To Assess	$412,625	$0	$0	$45,847	$0	?????
87.8%	0.0%	2.5%	4.8%	4.9%	Calculation	$888,733	$0	$25,564	$48,320	$49,339	
100.0%	0.0%	0.0%	0.0%	0.0%	Calculation	$1,154,222	$0	$0	$0	$0	
76.0%	0.0%	8.8%	12.3%	2.9%	Calculation	$203,642	$0	$23,566	$32,868	$7,855	
90.7%	0.0%	3.6%	3.6%	2.2%	Calculation	$292,885	$0	$11,475	$11,475	$7,027	
25.0%	0.0%	25.0%	25.0%	25.0%	To Assess	$127,617	$0	$127,617	$127,617	$127,617	?????
100.0%	0.0%	0.0%	0.0%	0.0%	To Assess	$896,883	$0	$0	$0	$0	Direct Assignmen
25.0%	0.0%	25.0%	25.0%	25.0%	To Assess	$287,090	$0	$287,090	$287,090	$287,090	?????
25.0%	0.0%	25.0%	25.0%	25.0%	To Assess	$320,080	$0	$320,080	$320,080	$320,080	?????
100.0%	0.0%	0.0%	0.0%	0.0%	To Assess	$1,439,963	$0	$0	$0	$0	?????
25.0%	0.0%	25.0%	25.0%	25.0%	To Assess	$574,989	$0	$574,989	$574,989	$574,989	?????
30.0%	0.0%	0.0%	50.0%	20.0%	To Assess	$706,606	$0	$0	$1,177,677	$471,071	Direct Assignmen
0.0%	0.0%	0.0%	80.0%	20.0%	To Assess	$0	$0	$0	$1,649,439	$412,360	Direct Assignmen
0.0%	0.0%	0.0%	80.0%	20.0%	To Assess	$0	$0	$0	$754,196	$188,549	?????
0.0%	0.0%	0.0%	80.0%	20.0%	To Assess	$0	$0	$0	$1,682,052	$420,513	Direct Assignmen
0.0%	0.0%	0.0%	80.0%	20.0%	To Assess	$0	$0	$0	$668,716	$167,179	Direct Assignmen
27.4%	0.0%	8.3%	45.6%	18.7%	Calculation	$68,041	$0	$20,472	$113,191	$46,413	Not a direct cost
42.5%	0.0%	19.2%	19.2%	19.2%	Calculation	$150,537	$0	$67,791	$67,791	$67,791	Not a direct cost
11.4%	0.0%	0.0%	68.6%	20.0%	Calculation	$109,481	$0	$0	$658,494	$191,994	Not a direct cost
92.0%	0.0%	0.0%	6.0%	2.0%	To assess	$20,002,813	$0	$0	$1,304,531	$434,844	?????
90.0%	0.0%	0.0%	7.0%	3.0%	To assess	$26,715,130	$0	$0	$2,077,843	$890,504	?????
100.0%	0.0%	0.0%	0.0%	0.0%	To assess	$2,321,654	$0	$0	$0	$0	All CAS
100.0%	0.0%	0.0%	0.0%	0.0%	To assess	$2,508,556	$0	$0	$0	$0	?????
25.0%	0.0%	25.0%	25.0%	25.0%	To assess	$266,088	$0	$266,088	$266,088	$266,088	?????
90.4%	0.0%	0.5%	6.4%	2.8%	Calculation	$191,858	$0	$985	$13,510	$5,893	
76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	$188,886	$0	$6,924	$36,600	$15,909	
76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	$4,993,700	$0	$183,066	$967,629	$420,606	
76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	$327,823	$0	$12,018	$63,522	$27,612	
76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	$1,239,795	$0	$45,450	$240,235	$104,425	
76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	$1,963,376	$0	$71,976	$380,443	$165,370	
76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	$1,148,209	$0	$42,093	$222,488	$96,711	
84.3%	0.0%	4.2%	6.6%	4.9%	Calculation	$272,829	$0	$13,460	$21,389	$15,861	
76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	$621,074	$0	$22,768	$120,345	$52,311	
76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	$1,014,171	$0	$37,179	$196,516	$85,421	
76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	$802,572	$0	$29,422	$155,514	$67,598	
76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	$585,792	$0	$21,475	$113,509	$49,340	
76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	$1,156,673	$0	$42,403	$224,129	$97,423	
0.0%	0.0%	0.0%	80.0%	20.0%	Department	$0	$0	$0	$2,443,104	$610,776	Direct Assignmen
0.0%	0.0%	0.0%	80.0%	20.0%	Department	$0	$0	$0	$512,600	$128,150	Direct Assignmen
40.0%	0.0%	40.0%	15.0%	5.0%	Department	$582,758	$0	$582,758	$218,534	$72,845	?????
0.0%	0.0%	33.0%	50.0%	17.0%	Department	$0	$0	$137,343	$208,096	$70,752	?????
76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	$322,858	$0	$11,827	$62,382	$27,137	

Allocation						Cost Allocated					
Control Area Services	Dynamic Dispatch Export Service	Scheduling Service	Market Operations Service	Real Time Market Operations Service	Allocation/ Assignment Method	Control Area Services	Dynamic Dispatch Export Service	Scheduling Service	Market Operations Service	Real Time Market Operations Service	Cost-Allocation Reasoning
76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	$1,650,449	$0	$60,462	$318,895	$138,725	
76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	$1,911,106	$0	$70,010	$369,258	$160,634	
76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	$4,424,193	$0	$162,073	$854,829	$371,866	
76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	$1,695,080	$0	$62,097	$327,518	$142,476	
58.7%	0.0%	6.0%	26.5%	8.8%	Calculation	$226,632	$0	$23,115	$102,236	$34,002	
76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	$9,984,000	$0	$365,748	$1,929,078	$839,184	
76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	$378,593	$0	$13,869	$73,150	$31,822	
76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	$658,961	$0	$24,140	$127,322	$55,388	
76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	$528,003	$0	$19,343	$102,019	$44,380	
76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	$500,614	$0	$18,339	$96,727	$42,078	
76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	$1,088,944	$0	$39,892	$210,402	$91,529	
60.0%	0.0%	20.0%	15.0%	5.0%	To assess	$545,765	$0	$181,922	$136,441	$45,480	Direct Allocation 7
76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	$556,281	$0	$20,378	$107,483	$46,757	
76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	$3,649,311	$0	$133,687	$705,109	$306,735	
76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	$124,134	$0	$4,547	$23,985	$10,434	
76.0%	0.0%	2.9%	2.9%	2.9%	Calculation	$2,539,295	$0	$96,531	$96,531	$96,531	
						$130,491,202	**$0**	**$4,960,586**	**$24,908,445**	**$10,865,824**	
						76.0%	0.0%	2.9%	14.7%	6.4%	
76.0%	0.0%	2.9%	14.7%	6.4%	Operating Costs	($951,546)	$0	($36,219)	($184,543)	($80,092)	
76.0%	0.0%	2.9%	14.7%	6.4%	Operating Costs	($91,173)	$0	($3,470)	($17,682)	($7,674)	
100.0%	0.0%	0.0%	0.0%	0.0%	Direct Assignmer	($1,255,891)	$0	$0	$0	$0	All CAS
						($2,298,610)	**$0**	**($39,689)**	**($202,225)**	**($87,766)**	
						87.5%	0.0%	1.5%	7.7%	3.3%	
						$128,192,592	**$0**	**$4,920,897**	**$24,706,219**	**$10,778,057**	
						75.8%	0.0%	2.9%	14.8%	6.4%	
100.0%	0.0%	0.0%	0.0%	0.0%	Direct Assignmer	$16,470,000	$0	$0	$0	$0	All CAS
10.0%	0.0%	75.0%	10.0%	5.0%	Direct Assignmer	$2,710,200	$0	$20,326,500	$2,710,200	$1,355,100	?????
55.0%	0.0%	20.0%	15.0%	10.0%	Direct Assignmer	$17,424,550	$0	$6,336,200	$4,752,150	$3,168,100	?????
25.0%	0.0%	25.0%	25.0%	25.0%	Direct Assignmer	$12,043,250	$0	$12,043,250	$12,043,250	$12,043,250	?????
50.0%	0.0%	20.0%	20.0%	10.0%	Direct Assignmer	$4,083,000	$0	$1,633,200	$1,633,200	$816,600	?????
100.0%	0.0%	0.0%	0.0%	0.0%	Direct Assignmer	$56,000	$0	$0	$0	$0	?????
0.0%	0.0%	0.0%	80.0%	20.0%	Direct Assignmer	$0	$0	$0	$190,400	$47,600	?????
50.0%	0.0%	30.0%	15.0%	5.0%	Direct Assignmer	$48,000	$0	$28,800	$14,400	$4,800	?????
0.0%	0.0%	0.0%	80.0%	20.0%	Direct Assignmer	$0	$0	$0	$8,800	$2,200	?????
100.0%	0.0%	0.0%	0.0%	0.0%	Direct Assignmer	$975,000	$0	$0	$0	$0	?????
70.0%	0.0%	15.0%	10.0%	5.0%	Direct Assignmer	$734,300	$0	$157,350	$104,900	$52,450	?????
60.0%	0.0%	20.0%	15.0%	5.0%	Direct Assignmer	$534,600	$0	$178,200	$133,650	$44,550	?????
70.0%	0.0%	15.0%	10.0%	5.0%	Direct Assignmer	$11,900	$0	$2,550	$1,700	$850	?????
100.0%	0.0%	0.0%	0.0%	0.0%	Direct Assignmer	$1,162,000	$0	$0	$0	$0	?????
						$56,252,800	$0	$40,706,050	$21,592,650	$17,535,500	
75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	$524,563	$0	$20,136	$102,718	$44,583	
75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	$5,300,966	$0	$203,487	$1,038,011	$450,536	
75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	$2,268,810	$0	$87,092	$444,268	$192,829	
75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	$1,300,037	$0	$49,904	$254,567	$110,492	
75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	$103,093	$0	$3,957	$20,187	$8,762	
75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	$28,805	$0	$1,106	$5,641	$2,448	
75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	$151,608	$0	$5,820	$29,687	$12,885	
75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	$969,532	$0	$37,217	$189,849	$82,402	
75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	$477,564	$0	$18,332	$93,515	$40,589	
75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	$8,009,439	$0	$307,456	$1,568,372	$680,732	
75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	$4,086,588	$0	$156,871	$800,217	$347,324	
75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	$1,008,192	$0	$38,701	$197,420	$85,687	
75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	$105,367	$0	$4,045	$20,633	$8,955	
75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	$2,639,491	$0	$101,322	$516,853	$224,334	
90.0%	0.0%	0.0%	7.0%	3.0%	Calculation	$24,336,000	$0	$0	$1,892,800	$811,200	
76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	$5,184,624	$0	$190,065	$1,004,625	$436,687	

Allocation						Cost Allocated					
Control Area Services	Dynamic Dispatch Export Service	Scheduling Service	Market Operations Service	Real Time Market Operations Service	Allocation/ Assignment Method	Control Area Services	Dynamic Dispatch Export Service	Scheduling Service	Market Operations Service	Real Time Market Operations Service	Cost-Allocation Reasoning
						$56,494,679	$0	$1,225,512	$8,179,363	$3,540,446	
						$112,747,479	$0	$41,931,562	$29,772,013	$21,075,946	
						54.9%	0.0%	20.4%	14.5%	10.3%	
						0	0	0	0	0	
54.9%	0.0%	20.4%	14.5%	10.3%	Calculation	$3,122,503	$0	$1,161,280	$824,526	$583,691	
54.9%	0.0%	20.4%	14.5%	10.3%	Calculation	$691,756	$0	$257,269	$182,665	$129,310	
54.9%	0.0%	20.4%	14.5%	10.3%	Calculation	$524,989	$0	$195,247	$138,628	$98,136	
75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	$40,097,983	$0	$1,539,231	$7,851,807	$3,407,978	
75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	$16,443,380	$0	$631,208	$3,219,869	$1,397,544	
						$60,880,610	$0	$3,784,235	$12,217,495	$5,616,660	
94.0%	0.0%	2.0%	2.0%	2.0%	To assess	$1,552,086	$0	$33,023	$33,023	$33,023	
15.0%	0.0%	66.0%	12.0%	7.0%	To assess	$685,398	$0	$3,015,753	$548,319	$319,853	
50.0%	0.0%	30.0%	15.0%	5.0%	To assess	$620,357	$0	$372,214	$186,107	$62,036	
75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	$3,365,365	$0	$129,185	$658,991	$286,027	
75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	$1,116,774	$0	$42,869	$218,682	$94,916	
						$7,339,980	$0	$3,593,045	$1,645,121	$795,854	
						$180,968,070	$0	$49,308,841	$43,634,629	$27,488,460	
						60.0%	0.0%	16.4%	14.5%	9.1%	
75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	$7,049,762	$0	$270,617	$1,380,453	$599,168	
56.0%	0.0%	14.0%	25.0%	5.0%	To assess	$8,530,763	$0	$2,132,691	$3,808,377	$761,675	
100.0%	0.0%	0.0%	0.0%	0.0%	To assess	$1,435,154	$0	$0	$0	$0	
75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	$3,032,576	$0	$116,411	$593,825	$257,742	
100.0%	0.0%	0.0%	0.0%	0.0%	To assess	$5,286,679	$0	$0	$0	$0	
38.0%	0.0%	12.0%	50.0%	0.0%	To assess	$320,760	$0	$101,293	$422,053	$0	
						$25,655,695	$0	$2,621,012	$6,204,708	$1,618,586	
						71.1%	0.0%	7.3%	17.2%	4.5%	
						$206,623,764	$0	$51,929,853	$49,839,337	$29,107,046	
						61.2%	0.0%	15.4%	14.8%	8.6%	
61.2%	0.0%	15.4%	14.8%	8.6%	Calculation	$33,516,663	$0	$8,423,597	$8,084,492	$4,721,485	
						$33,516,663	**$0**	**$8,423,597**	**$8,084,492**	**$4,721,485**	
						61.2%	0.0%	15.4%	14.8%	8.6%	
80.0%	0.0%	7.0%	10.0%	3.0%	To assess	$2,554,400	$0	$223,510	$319,300	$95,790	
75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	$337,327	$0	$12,949	$66,054	$28,670	
75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	$2,516,689	$0	$96,608	$492,807	$213,897	
40.0%	0.0%	21.0%	29.0%	10.0%	To assess	$6,016,800	$0	$3,158,820	$4,362,180	$1,504,200	
						$11,425,216	**$0**	**$3,491,886**	**$5,240,341**	**$1,842,556**	
						51.9%	0.0%	15.9%	23.8%	8.4%	
75.8%	0.0%	2.9%	14.8%	6.4%		$130,491,202	$0	$4,960,586	$25,304,324	$10,983,017	
87.5%	0.0%	1.5%	7.7%	3.3%		($2,298,610)	$0	($39,689)	($202,225)	($87,766)	
76.0%	0.0%	2.9%	14.7%	6.4%		$128,192,592	$0	$4,920,897	$25,102,099	$10,895,251	
61.2%	0.0%	15.4%	14.8%	8.6%		$33,516,663	$0	$8,423,597	$8,084,492	$4,721,485	
51.9%	0.0%	15.9%	23.8%	8.4%		$11,425,216	$0	$3,491,886	$5,240,341	$1,842,556	
						$173,134,471	**$0**	**$16,836,381**	**$38,426,932**	**$17,459,292**	
						70.4%	0.0%	6.8%	15.6%	7.1%	
						$ (5,814,436)	$ -	$ (565,422)	$ (1,290,505)	$ (586,342)	
						$167,320,035	**$0**	**$16,270,959**	**$37,136,426**	**$16,872,951**	
						70.4%	0.0%	6.8%	15.6%	7.1%	

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1	1500	Operations - Direct Costs										
2	1521	Grid Planning	$ 2,041,338		100.0%	0.0%	0.0%		Direct Assignment	$ 2,041,338	$ -	$ -
3				$ 2,425,338	100.0%	0.0%	0.0%	Department	Direct Assignment	$ 2,425,338	$ -	$ -
4	1542	Outage Coordination	$ 1,580,356		100.0%	0.0%	0.0%		Direct Assignment	$ 1,580,356	$ -	$ -
5		Total Costs		$ 1,780,930	100.0%	0.0%	0.0%	Department	Direct Assignment	$ 1,780,930	$0	$0
6	1543	Loads and Resources	$ 943,936		100.0%	0.0%	0.0%		Direct Assignment	$ 943,936	$ -	$ -
7		Total Costs		$ 1,006,436	100.0%	0.0%	0.0%	Department	Direct Assignment	$ 1,006,436	$ -	$ -
8	1544	Real-Time Scheduling	$ 2,578,768		75.0%	15.0%	10.0%		Direct Assignment	$ 1,934,076	$ 386,815	$ 257,877
9		Total Costs		$ 2,680,968	75.0%	15.0%	10.0%	Department	Direct Assignment	$ 2,010,726	$402,145	$268,097
10	1545	Grid Operations - General	$ 6,844,825		79.4%	10.3%	10.3%		Direct Assignment	$ 5,435,343	$ 704,741	$ 704,741
11		Total Costs		$ 7,167,325	79.6%	10.2%	10.2%	Department	Direct Assignment	$ 5,702,047	$733,879	$731,399
12	1546	Security Coordination	$ 1,207,891		100.0%	0.0%	0.0%		Direct Assignment	$ 1,207,891	$ -	$ -
13		Total Costs		$ 1,255,891	100.0%	0.0%	0.0%	Department	Direct Assignment	$ 1,255,891	$0	$0
14	1554	Special Projects Engineer	$ 601,931		81.3%	0.0%	18.7%		Direct Assignment	$ 489,655	$ -	$ 112,276
15		Total Costs		$ 860,981	84.2%	-0.1%	15.9%	Department	Direct Assignment	$ 725,153	($1,118)	$136,945
16	1555	Operations Support Group	$ 974,683		60.3%	22.0%	17.7%		Direct Assignment	$ 588,100	$ 214,032	$ 172,551
17		Total Costs		$ 1,025,163	60.6%	21.5%	18.0%	Department	Direct Assignment	$ 620,880	$220,082	$184,201
18	1558	Transmission Maintenanc	$ 1,141,103		97.4%	0.0%	2.6%		Direct Assignment	$ 1,111,005	$ -	$ 30,098
19		Total Costs		$ 1,804,953	98.2%	0.0%	1.8%	Department	Direct Assignment	$ 1,773,365	$0	$31,588
20	1561	Operations Engineering S	$ 1,034,681		100.0%	0.0%	0.0%		Direct Assignment	$ 1,034,681	$ -	$ -
21		Total Costs		$ 1,240,187	100.0%	0.0%	0.0%	Department	Direct Assignment	$ 1,240,187	$0	$0
22	1562	Operations Engineering N	$ 1,168,863		100.0%	0.0%	0.0%		Direct Assignment	$ 1,168,863	$ -	$ -
23		Total Costs		$ 1,226,703	100.0%	0.0%	0.0%	Department	Direct Assignment	$ 1,226,703	$0	$0
24	1563	Coordinated Operations	$ 584,551		60.0%	10.0%	30.0%		Direct Assignment	$ 350,731	$ 58,455	$ 175,365
25		Total Costs		$ 677,951	60.0%	10.0%	30.0%	Department	Direct Assignment	$ 406,771	$67,795	$203,385
26	1565	Pre-Scheduling and Supp	$ 1,660,765		73.3%	15.0%	11.7%		Direct Assignment	$ 1,217,556	$ 248,314	$ 194,895
27		Total Costs		$ 1,697,365	73.9%	14.6%	11.5%	Department	Direct Assignment	$ 1,254,021	$248,406	$194,938
28	1566	Regional Coordination - G	$ 423,012		77.3%	0.0%	22.7%		Direct Assignment	$ 327,193	$ -	$ 95,819
29		Total Costs		$ 554,912	83.2%	0.0%	16.8%	Department	Direct Assignment	$ 461,569	$0	$93,343

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30	1549	Operations Training	$ 1,919,268		62.1%	24.6%	13.3%		Direct Assignment	$ 1,191,898	$ 472,917	$ 254,453
31		Total Costs		$ 3,064,253	61.7%	24.1%	14.2%	Department	Direct Assignment	$ 1,890,463	$737,849	$435,942
32	1559	Operations Application Su	$ 447,958		78.5%	10.7%	10.7%		Direct Assignment	$ 351,831	$ 48,063	$ 48,063
33				$ 458,472	78.9%	10.5%	10.6%	Department	Direct Assignment	$ 361,629	$48,126	$48,717
34	**Total Operations Direct Salary Cost C**		**$ 25,153,929**							$ 20,974,453	$ 2,133,338	$ 2,046,138
35	**Total Operations Direct Salary %**								**Allocation %**	83.4%	8.5%	8.1%
36	**Total Operations Direct Costs**			**$ 28,927,828**						$ 24,142,109	$ 2,457,164	$ 2,328,555
37	**Total Operations Direct Costs %**								**Allocation %**	83.5%	8.5%	8.0%
38	**1500**	**Operations - Indirect Costs**										
39	1511	VP Grid Operations - Gen	$ 365,202		66.4%	18.3%	15.3%		Allocated based on Department Direct Costs	$ 242,495	$ 66,786	$ 55,921
40		Total		$ 1,011,957	66.4%	18.3%	15.3%	Calculation	Allocated based on Department Direct Costs	$ 671,941	$ 185,061	$ 154,956
41	1547	Engineering and Maintena	$ 289,222		99.3%	0.0%	0.7%		Allocated based on Supervised Departments costs	$ 287,192	$ -	$ 2,030
42		Total Costs		$ 1,154,222	99.4%	0.0%	0.6%	Calculation	Allocated based on Supervised Departments costs	$ 1,147,315	$ -	$ 6,907
43	1548	OSAT	$ 182,432		72.7%	9.0%	18.3%		Allocated based on Supervised Departments costs	$ 132,563	$ 16,441	$ 33,429
44		Total Costs		$ 267,932	76.5%	6.5%	17.0%	Calculation	Allocated based on Supervised Departments costs	$ 205,048	$ 17,342	$ 45,543
45	1564	Operations Scheduling - C	$ 281,362		81.3%	10.9%	7.8%		Allocated based on Supervised Departments costs	$ 228,768	$ 30,705	$ 21,889
46		Total Costs		$ 322,862	81.9%	10.6%	7.5%	Department	Allocated based on Supervised Departments costs	$ 264,489	$34,101	$24,272
47	**Total Operations Indirect Salaries**		**$ 1,118,218**							$ 891,017	$ 113,932	$ 113,269
48	**Total Operations Indirect Costs**			**$ 2,756,973**						$ 2,288,792	$ 236,504	$ 231,677
49	**Total Operations Salaries**		**$ 26,272,147**							$ 21,865,470	$ 2,247,270	$ 2,159,407
50	**Total Operations Costs**			**$ 31,684,801**						$ 26,430,900	$ 2,693,668	$ 2,560,233
51	**Operations Indirect Costs as % of Total**			9%								
52	**1700**	**VP Market Services**										
53	1722	Application Support	$ 414,256		19.0%	7.0%	74.0%		Direct Assignment	$ 78,709	$ 28,998	$ 306,549
54		Total Costs		$ 510,466	19.0%	7.0%	74.0%	Department	Direct Assignment	$ 96,796	$ 35,712	$ 377,957
55	1723	Tariff and Contract Implen	$ 667,205		90.0%	0.0%	10.0%		Direct Assignment	$ 600,485	$ -	$ 66,721
56		Total Costs		$ 896,883	90.0%	0.0%	10.0%	Department	Direct Assignment	$ 807,195	$ -	$ 89,688

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					Control Area Services	Congestion Mgmt.	ASREO/MO			Control Area Services	Congestion Mgmt.	ASREO/MO
57												
58	1724	BBS - PSS	$ 942,333		17.0%	7.8%	75.2%		Direct Assignment	$ 159,879	$ 73,833	$ 708,621
59		Total Costs		$ 1,148,361	16.8%	7.7%	75.5%	Department	Direct Assignment	$ 193,228	$ 88,510	$ 866,623
60	1725	BBS - FSS	$ 1,037,777		15.6%	7.3%	77.2%		Direct Assignment	$ 161,664	$ 75,294	$ 800,819
61		Total Costs		$ 1,280,321	15.6%	7.4%	77.0%	Department	Direct Assignment	$ 200,292	$ 94,667	$ 985,362
62	1731	Contracts and Special Prc	$ 1,153,955		74.4%	2.4%	23.2%		Direct Assignment	$ 859,049	$ 27,655	$ 267,251
63		Total Costs		$ 1,439,963	76.6%	2.4%	21.0%	Department	Direct Assignment	$ 1,102,613	$ 34,935	$ 302,416
64	1741	Client Relations	$ 2,054,540		40.7%	9.3%	50.0%		Direct Assignment	$ 836,710	$ 190,286	$ 1,027,544
65		Total Costs		$ 2,299,956	37.8%	9.5%	52.7%	Department	Direct Assignment	$ 869,540	$ 218,093	$ 1,212,323
66	1752	Manager of Markets	$ 2,156,353		29.0%	30.0%	41.0%		Direct Assignment	$ 625,342	$ 646,906	$ 884,105
67		Total Costs		$ 2,355,353	28.8%	30.0%	41.2%	Department	Direct Assignment	$ 677,679	$ 706,606	$ 971,068
68	1753	Market Engineering	$ 1,680,883		32.8%	27.6%	39.6%		Direct Assignment	$ 550,812	$ 464,413	$ 665,658
69		Total Costs		$ 2,061,799	31.7%	28.1%	40.2%	Department	Direct Assignment	$ 653,659	$ 578,688	$ 829,452
70	1755	Business Solutions	$ 739,166		26.0%	10.0%	64.0%		Direct Assignment	$ 192,183	$ 73,917	$ 473,066
71		Total Costs		$ 942,745	25.2%	10.5%	64.3%	Department	Direct Assignment	$ 237,599	$ 98,675	$ 606,471
72	1756	Market Quality - General	$ 1,940,408		37.0%	33.0%	30.0%		Direct Assignment	$ 717,951	$ 640,335	$ 582,122
73		Total Costs		$ 2,102,565	37.1%	33.1%	29.8%	Department	Direct Assignment	$ 780,139	$ 695,886	$ 626,540
74	1757	Market Integration	$ 587,361		25.0%	30.0%	45.0%		Direct Assignment	$ 146,840	$ 176,208	$ 264,312
75				$ 835,895	25.1%	30.0%	44.9%	Department	Direct Assignment	$ 210,108	$ 250,769	$ 375,019
76	**Total Market Services Direct Salaries**		**$13,374,237**							4,929,623	2,397,845	6,046,769
77	**Total Market Services Direct Salaries %**								**Allocation %**	36.9%	17.9%	45.2%
78	**Total Market Services Direct Costs**			**$15,874,307**						5,828,847	2,802,541	7,242,919
79	**Total Market Services Direct Costs %**								**Allocation %**	36.7%	17.7%	45.6%

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80	1700	Market Services - Indirect Costs										
81	1711	VP Market Services - Gen	$ 394,287		36.9%	17.9%	45.2%		Allocated based on Department Direct Costs	$ 145,331	$ 70,691	$ 178,265
82		Total		$ 248,117	36.9%	17.9%	45.2%	Calculation	Allocated based on Department Direct Costs	91,454	44,484	112,179
83	1721	Billing and Settlements-G	$ 347,911		32.7%	5.8%	61.5%		Allocated based on Supervised Departments	$ 113,722	$ 20,242	$ 213,948
84		Total Costs		$ 353,911	33.8%	5.7%	60.5%	Calculation	Allocated based on Supervised Departments costs	$ 119,708	$ 20,195	$ 214,008
85	1751	Market Operations - Gene	$ 331,747		20.0%	30.0%	50.0%		Allocated based on Supervised Departments	$ 66,349	$ 99,524	$ 165,874
86		Total Costs		$ 959,968	20.0%	30.0%	50.0%	Calculation	Allocated based on Supervised Departments	$ 191,994	$ 287,990	$ 479,984
87	**Total Market Services Indirect Salarie**		**$ 1,073,945**							325,402	190,457	558,086
88	**Total Market Services Indirect Costs**			**$ 1,561,996**						403,155	352,670	806,171
89	**Total Market Services Salaries**		**14,448,182**							**5,255,025**	**2,588,302**	**6,604,855**
90	**Total Market Services Costs**			**$17,436,303**						6,232,002	3,155,210	8,049,090
91	**Market Services Indirect as % of Total**			9%						35.74%	18.10%	46.16%
92	1400	Information Services - Direct Costs										
93	1424	Asset Management	$ 845,319		56.0%	5.0%	39.0%		Direct Assignment	$ 473,379	$ 42,266	$ 329,674
94		Total Costs		$ 21,742,188	67.3%	6.9%	25.9%	Department	Direct Assignment	$ 14,627,029	$1,493,935	$5,621,224
95	1441	Outsourced Contracts	$ 159,466		60.1%	10.7%	29.2%		Allocated based on	$ 95,797	$ 17,056	$ 46,614
96		Total Costs		$ 29,683,478	60.1%	10.7%	29.2%	Calculation	Allocated based on Labor Dollar Ratios-Special	$ 17,831,873	$3,174,793	$8,676,812
97	1461	Control Systems	$ 2,186,977		100.0%	0.0%	0.0%		Direct Assignment	$ 2,186,977	$ -	$ -
98		Total Costs		$ 2,321,654	100.0%	0.0%	0.0%	Department	Direct Assignment	$ 2,321,654	$0	$0
99	1462	Field Data Acquisition Sys	$ 1,805,783		28.6%	11.3%	60.1%		Direct Assignment	$ 515,566	$ 204,658	$ 1,085,560
100		Total Costs		$ 2,508,556	29.9%	8.2%	61.9%	Department	Direct Assignment	$ 749,148	$205,422	$1,553,986
101	1467	Settlement Systems Servi	$ 980,615		15.0%	7.0%	78.0%		Direct Assignment	$ 147,092	$ 68,643	$ 764,880
102		Total Costs		$ 1,064,350	15.0%	7.0%	78.0%	Department	Direct Assignment	$ 159,653	$74,505	$830,193
103	**Total IS Direct Salaries**		**$ 5,978,160**							$ 3,418,810	$ 332,623	$ 2,226,727
104	**Total IS Direct Salaries %**								**Allocation %**	57.2%	5.6%	37.2%
105	**Total IS Direct Costs**			**$ 57,320,226**						$ 35,689,357	$ 4,948,655	$ 16,682,215
106	**Total IS Direct Cost %**								**Allocation %**	62.26%	8.63%	29.10%
107	1600	Legal - Direct Costs										
108	1641	Market Analysis	$ 1,997,346		25.1%	18.7%	56.2%		Direct Assignment	$ 501,536	$ 373,952	$ 1,121,857
109		Total		$ 3,053,880	22.6%	19.3%	58.1%	Department	Direct Assignment	$ 688,824	$ 589,477	$ 1,775,579
110	1642	Market Surveillance Comr	$ -		0.0%	0.0%	0.0%			$ -	$ -	$ -
111		Total		$ 640,750	9.2%	25.0%	65.8%	Department	Direct Assignment	$ 59,075	$ 160,188	$ 421,488
112	1661	Compliance - General	$ 1,150,095		83.3%	5.6%	11.1%		Direct Assignment	$ 958,413	$ 63,894	$ 127,788

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113				$ 1,456,895	81.8%	5.5%	12.7%	Department	Direct Assignment	$ 1,191,963	$ 80,118	$ 184,814
114	1662	Compliance - Audits	$ 357,191		83.3%	5.6%	11.1%		Direct Assignment	$ 297,659	$ 19,844	$ 39,688
115		Total Costs		$ 416,191	83.7%	4.8%	11.5%	Department	Direct Assignment	$ 348,359	$ 19,916	$ 47,916
116	**Total Legal Direct Salaries**		**$ 3,504,632**							$ 1,757,608	$ 457,691	$ 1,289,333
117	**Total Legal Direct Salaries %**								**Allocation %**	50.2%	13.1%	36.8%
118	**Total Legal Direct Costs**			**$ 5,567,716**						$ 2,288,222	$ 849,698	$ 2,429,796
119	**Total Legal Direct Cost %**								**Allocation %**	41.1%	15.3%	43.6%
120	**Subtotal Salaries Operations, Market Services, Indirec**			**$ 50,203,121**						$ 32,296,913	$ 5,625,885	$ 12,280,323
121	**Salary Percentages**									64.3%	11.2%	24.5%
122	**Subtotal Costs Operations, Market Services, Indirect I**			**$ 112,009,046**						$ 70,640,481	$ 11,647,231	$ 29,721,334
123	**Expense Percentages**									63.1%	10.4%	26.5%
124	1400	VP Information Services Indirect Costs										
125	1411	Chief Information Officer-	$ 391,143		62.3%	8.6%	29.1%		Allocated based on Department Direct Costs	$ 243,538	$ 33,769	$ 113,836
126		Total		$ 212,246	62.3%	8.6%	29.1%	Calculation	Allocated based on Department Direct Costs	$ 132,151	$18,324	$61,771
127	1422	Corporate & Enterprise Ap	$ 233,320		61.7%	10.0%	28.3%		Allocated based on Supervised Departments costs	$ 144,023	$ 23,246	$ 66,051
128		Total Costs		$ 248,320	61.7%	10.0%	28.3%	Calculation	Allocated based on Supervised Departments costs	$ 153,231	$ 24,743	$ 70,346
129	1466	Enterprise Applications	$ 764,123		61.8%	9.4%	28.9%		Allocated based on Direct Operating Costs	$ 471,923	$ 71,511	$ 220,689
130		Total Costs		$ 816,499	61.8%	9.4%	28.9%	Calculation	Allocated based on Direct Operating Costs	$ 504,271	$ 76,413	$ 235,815
131	1431	End User Support	$ 491,206		63.1%	10.4%	26.5%		Allocated based on Direct Operating Costs	$ 309,788	$ 51,078	$ 130,340
132		Total Costs		$ 6,565,001	63.1%	10.4%	26.5%	Calculation	Allocated based on Direct Operating Costs	$ 4,140,334	$682,660	$ 1,742,007
133	1432	Computer Operations - Ge	$ 403,068		58.2%	9.6%	32.2%		Allocated based on Supervised Departments costs	$ 234,551	$ 38,673	$ 129,844
134		Total Costs		$ 430,975	60.7%	10.0%	29.2%	Calculation	Allocated based on Supervised Departments costs	$ 261,804	$43,166	$ 126,005
135	1433	Network Operations	$ 1,549,597		63.1%	10.4%	26.5%		Allocated based on Labor Dollar Ratios-Special	$ 977,281	$ 161,134	$ 411,182
136		Total Costs		$ 1,629,905	63.1%	10.4%	26.5%	Calculation	Allocated based on Labor Dollar Ratios-Special	$ 1,027,928	$169,485	$ 432,491

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137	1442	Production Support	$ 2,440,565		56.2%	9.3%	34.5%		Allocated based on Direct Operating Costs	$ 1,371,349	$ 226,109	$ 843,108
138		Total Costs		$ 2,581,165	56.2%	9.3%	34.5%	Calculation	Allocated based on Direct Operating Costs	$ 1,450,351	$239,135	$891,679
139	1451	Information Security	$ 1,038,281		63.1%	10.4%	26.5%		Allocated based on Direct Operating Costs	$ 654,810	$ 107,965	$ 275,505
140		Total Costs		$ 1,509,500	63.1%	10.4%	26.5%	Calculation	Allocated based on Direct Operating Costs	$ 951,993	$156,965	$ 400,542
141	1463	Operations Applications -	$ 292,237		73.8%	1.8%	24.3%		Allocated based on Supervised Departments costs	$ 215,714	$ 5,384	$ 71,140
142		Total Costs		$ 323,539	74.3%	1.6%	24.1%	Calculation	Allocated based on Supervised Departments costs	$ 240,496	$5,081	$ 77,963
143	1471	IT Planning	$ 628,349		63.1%	10.4%	26.5%		Allocated based on Direct Operating Costs	$ 396,279	$ 65,339	$ 166,731
144		Total Costs		$ 770,116	63.1%	10.4%	26.5%	Calculation	Allocated based on Direct Operating Costs	$ 485,687	$80,080	$ 204,348
145	1468	Corporate Application Sup	$ 1,188,702		60.6%	10.0%	29.4%		Allocated based on Direct Operating Costs	$ 720,334	$ 118,769	$ 349,599
146				$ 1,333,287	60.6%	10.0%	29.4%	Calculation	Allocated based on Direct Operating Costs	$ 807,950	$133,215	$392,122
147	1469	Analytical and Reporting	$ 984,106		63.1%	10.4%	26.5%		Allocated based on Direct Operating Costs	$ 620,644	$ 102,332	$ 261,130
148				$ 1,055,106	63.1%	10.4%	26.5%	Calculation	Allocated based on Direct Operating Costs	$ 665,421	$109,715	$279,970
149	1481	Markets and Scheduling	$ 1,267,761		56.2%	9.3%	34.6%		Allocated based on Direct Operating Costs	$ 712,015	$ 117,397	$ 438,348
150		Total Costs		$ 1,520,628	56.2%	9.3%	34.6%	Calculation	Allocated based on Direct Operating Costs	$ 854,034	$140,813	$525,781
151	**Total IS Indirect Salaries**		**$ 11,672,458**							$ 7,072,249	$ 1,122,706	$ 3,477,503
152	**Total IS Indirect Costs**			**$ 18,996,287**						$ 11,675,650	$ 1,879,796	$ 5,440,841
153	**Total IS Operating Salaries**		**$ 17,650,618**							$ 10,491,059	$ 1,455,329	$ 5,704,230
154	**Total IS Operating Costs**			**$76,316,513**						$ 47,365,006	$ 6,828,450	$ 22,123,056
155	**IS Indirect Costs as % of IT Operating Costs**			25%								
156	Operating Costs and Salaries Before Corporate Indirects											
157	**Total Operating Salaries**		**$ 61,875,579**							**$ 39,369,162**	**$ 6,748,591**	**$ 15,757,826**
158	**Total Operating Salaries %**								**Allocation %**	63.6%	10.9%	25.5%

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159	**Total Operating Costs**			**$131,005,333**						**$82,316,131**	**$13,527,027**	**$35,162,175**
160	**Total Operating Costs %**								**Allocation %**	62.8%	10.3%	26.8%
161	**1300**	**Finance - Corporate Indirect Costs**										
162	1321	Accounting	$ 836,830		47.4%	7.8%	44.8%		Allocated based on Direct Operating Costs	$ 396,423	$ 65,192	$ 375,214
163		Total		$ 2,168,530	47.4%	7.8%	44.8%	Calculation	Allocated based on Direct Operating Costs	$ 1,027,277	$ 168,937	$ 972,316
164	1331	Financial Planning and Tr	$ 714,782		59.8%	10.3%	29.9%		Allocated based on Direct Operating Costs	$ 427,335	$ 73,671	$ 213,776
165		Total		$ 2,511,009	59.8%	10.3%	29.9%	Calculation	Allocated based on Direct Operating Costs	$ 1,501,215	$ 258,804	$ 750,990
166	1351	Facilities	$ 641,351		63.6%	10.9%	25.5%		Allocated based on Labor Dollar Ratios	$ 408,068	$ 69,950	$ 163,333
167		Total		$ 5,812,962	63.6%	10.9%	25.5%	Calculation	Allocated based on Labor Dollar Ratios	$ 3,698,575	$ 634,003	$ 1,480,384
168	1361	Office Administration	$ 643,601		63.6%	10.9%	25.5%		Allocated based on Labor Dollar Ratios	$ 409,500	$ 70,196	$ 163,906
169		Total		$ 2,227,171	63.6%	10.9%	25.5%	Calculation	Allocated based on Labor Dollar Ratios	$ 1,417,067	$ 242,911	$ 567,193
170	**Total Finance Indirect Costs**			**$12,719,672**						$ 7,644,134	$ 1,304,655	$ 3,770,883
171	**Total Finance Op Salaries b/f CFO**		**$ 2,836,564**							$ 1,641,326	$ 279,009	$ 916,229
172	**Finance Indirect as % of Fin Operating Costs**			100%						60.1%	10.3%	29.6%
173	**1300**	**Finance - Based on Finance Corporate Indirect Costs**										
174												
175	1311	CFO - General	$ 420,090		58.8%	10.3%	30.9%		Allocated based on Supervised Departments costs	$ 246,988	$ 43,116	$ 129,986
176		Total		$ 424,204	60.9%	10.7%	28.4%	Calculation	Allocated based on Supervised Departments costs	$ 258,449	$ 45,232	$ 120,523
177	**Total Finance Op Salaries**		**$ 3,256,654**							$ 1,888,314	$ 322,125	$ 1,046,215
178	**Total Finance Operating Costs**			**$ 13,143,876**						$ 7,902,583	$ 1,349,887	$ 3,891,406
179	**Finance Indirect as % of Fin Operating Costs**			100%								
180	**1600**	**Legal: Chief Counsel - Corporate Indirect Costs**										
181	1631	Legal and Regulatory	$ 3,330,071		61.7%	10.1%	28.2%		Allocated based on Direct Operating Costs	$ 2,055,488	$ 335,067	$ 939,515
182		Total		$ 13,118,010	61.7%	10.1%	28.2%	Calculation	Allocated based on Direct Operating Costs	$ 8,097,100	$1,319,917	$3,700,993
183	**Total Legal Indirect Salaries**		**$ 3,330,071**							2,055,488.4	335,067.3	939,515.3
184	**Total Legal Indirect Costs**			**$ 13,118,010**						$ 8,097,100	$ 1,319,917	$ 3,700,993
185	**Total Legal Salaries**		**$ 6,834,703**							3,813,096.5	792,757.8	2,228,848.7
186	**Total Legal Costs**			**$18,685,726**						$10,385,322	$2,169,615	$6,130,789
187	**Indirect as % of Total**			70.2%						55.6%	11.6%	32.8%
188	**1600**	**Legal: Chief Counsel - Based on Legal Corporate Indirect and Direct Costs**										

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Line #	ISO Dept #	OPERATING COSTS	Amount Labor	Amount Total Costs	Allocation: Control Area Services	Allocation: Congestion Mgmt.	Allocation: ASREO/MO	Source	Allocation/ Assignment Method	Total Costs Assigned/Allocated: Control Area Services	Total Costs Assigned/Allocated: Congestion Mgmt.	Total Costs Assigned/Allocated: ASREO/MO
189	1611	VP General Counsel - Ge	$ 468,583		55.8%	11.6%	32.6%	Calculation	Allocated based on Supervised Departments costs	$ 261,424	$ 54,351	$ 152,808
190		Total		$ 385,985	57.3%	11.1%	31.6%	Calculation	Allocated based on Supervised Departments costs	$ 221,074	$42,980	$121,931
190	**Total Legal Salaries**		**$ 7,303,286**							4,074,520	847,109	2,381,657
191	**Total Legal Costs**			**$19,071,711**						$10,606,396	$2,212,595	$6,252,720
191	**Indirect as % of Total**			72%					Op Cost %	55.6%	11.6%	32.8%
192	**1800**	**VP Corporate and Strategic Development - Corporate Indirect Costs**										
193	1821	Communications	$ 452,711		63.6%	10.9%	25.5%		Allocated based on Direct Operating Costs	$ 288,043	$ 49,376	$ 115,292
194		Total Costs		$ 865,811	63.6%	10.9%	25.5%	Calculation	Allocated based on Direct Operating Costs	$ 550,884	$ 94,432	$ 220,496
195	1831	Strategic Development	$ 477,745		63.6%	10.9%	25.5%		Allocated based on Direct Operating Costs	$ 303,972	$ 52,106	$ 121,667
196				$ 693,745	63.6%	10.9%	25.5%	Calculation	Allocated based on Direct Operating Costs	$ 441,405	$ 75,665	$ 176,676
197	1851	Project Office	$ 583,258		62.8%	10.3%	26.8%		Allocated based on Direct Operating Costs	$ 366,485	$ 60,225	$ 156,548
198				$ 657,758	62.8%	10.3%	26.8%	Calculation	Allocated based on Direct Operating Costs	$ 413,297	$ 67,917	$ 176,544
199	1861	Regulatory Policy	$ 585,142		62.8%	10.3%	26.8%		Allocated based on Direct Operating Costs	$ 367,669	$ 60,419	$ 157,054
200		Total Costs		$ 1,430,767	62.8%	10.3%	26.8%	Calculation	Allocated based on Direct Operating Costs	$ 899,011	$ 147,735	$ 384,022
201	**Total Corporate and Strategic Devpt**		**$ 2,098,856**							$ 1,326,170	$ 222,126	$ 550,560
202	**Total Corporate and Strategic Devpt b/f HR**			**$3,648,081**						$ 2,304,596	$ 385,748	$ 957,737
203									Op Cost %	**63.2%**	**10.6%**	**26.3%**
204	**1800**	**VP Corporate and Strategic Development - Based on Corporate Indirect Costs**										
205	1811	VP Corporate and Strateg	$ 392,226		63.2%	10.6%	26.2%		Allocated based on Supervised Departments costs	$ 247,829	$ 41,510	$ 102,887
206		Total Costs		$ 497,434	63.2%	10.6%	26.3%	Calculation	Allocated based on Supervised Departments costs	$ 314,243	$ 52,599	$ 130,592
207	**Total Corporate and Strategic Devt b.**		**$ 2,491,082**							$ 1,573,999	$ 263,636	$ 653,447
208	**Total Corporate and Strategic Devt b/f HR**			**$4,145,515**						$ 2,618,839	$ 438,347	$ 1,088,329
209	**Cost Allocation Percentage**									63.2%	10.6%	26.3%
210	**1241**	**MD02**										
211	1241	MD02	$ 882,609		32.0%	33.0%	35.0%		Direct Assignment	$ 282,435	$ 291,261	$ 308,913
212		Total Costs		$ 909,609	32.0%	33.0%	35.0%	Calculation	Direct Assignment	$ 291,075	$ 300,171	$ 318,363
213	MD02		**$ 882,609**							**$ 282,435**	**$ 291,261**	**$ 308,913**

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Appendix C2

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Line #	ISO Dept #	OPERATING COSTS	Amount Labor	Amount Total Costs	Allocation: Control Area Services	Allocation: Congestion Mgmt.	Allocation: ASREO/MO	Source	Allocation/ Assignment Method	Total Costs Assigned/Allocated: Control Area Services	Total Costs Assigned/Allocated: Congestion Mgmt.	Total Costs Assigned/Allocated: ASREO/MO
214				$ 909,609						$ 291,075	$ 300,171	$ 318,363
215	Cost Allocation Percentage									32.0%	33.0%	35.0%
216												
217		Total Costs and Salaries before HR/CEO										
218		Total Costs and Salaries before HR/CEO										
219	Total Salaries before HR/CEO		$ 72,304,578							$ 45,430,822	$ 8,015,032	$ 18,858,725
220	Total Salaries before HR/CEO %								Allocation %	62.8%	11.1%	26.1%
221	Total Costs before HR/CEO			$ 162,708,328						$ 101,446,802	$ 16,978,328	$ 44,283,198
222	Total Costs before HR/CEO %								Allocation %	62.3%	10.4%	27.2%
223	1100/1200	CEO / Human Resources - Corporate Indirects										
224	1111	CEO - General	$ 744,874		62.8%	11.1%	26.1%			$ 468,023	$ 82,570	$ 194,281
225		Total		$ 730,899	62.8%	11.1%	26.1%	Calculation	Allocated based on Labor Dollar Ratios	$ 459,243	$ 81,021	$ 190,636
226	1841	Human Resources	$ 1,166,617		62.8%	11.1%	26.1%			$ 733,015	$ 129,321	$ 304,281
227		Total		$ 4,794,842	62.8%	11.1%	26.1%	Calculation	Allocated based on Labor Dollar Ratios	$ 3,012,722	$ 531,513	$ 1,250,607
228	1651	Board of Governors								$ -	$ -	$ -
229		Total		$ 163,100	62.8%	11.1%	26.1%	Calculation	Allocated based on Labor Dollar Ratios	$ 102,480	$ 18,080	$ 42,540
230	Total CEO/HR Salaries		$ 1,911,491							$ 1,201,039	$ 211,891	$ 498,562
231	Total CEO/HR Costs			$ 5,688,841						$ 3,574,445	$ 630,613	$ 1,483,783
232	Total Salaries Prior to Salary Adjustn		$ 74,216,069							$ 46,631,860	$ 8,226,923	$ 19,357,286
233	Total Salaries Prior to Salary Adjustments %								Allocation %	62.8%	11.1%	26.1%
234	Total Costs Prior to Salary Adjustments			168,397,169						$ 105,021,247	$ 17,608,942	$ 45,766,981
235	Total Costs Prior to Salary Adjustments &								Allocation %	62.4%	10.5%	27.2%
236		Other Costs										
237	All	Salary Adjustments, next	$ 3,341,960	$3,341,960	62.4%	10.5%	27.2%	Calculation	As distributed to various departments	2,084,220	349,462	908,278
238	Total Other Costs		$ 3,341,960	$3,341,960						$2,084,220	$349,462	$908,278
239		Gross Operating Costs										
240	Total Operating Salaries		$ 77,558,029							$ 48,716,081	$ 8,576,384	$ 20,265,564
241	Total Operating Salaries %								Allocation %	62.8%	11.1%	26.1%
242	Gross Operating Costs			$171,739,129						$107,105,467	$17,958,404	$46,675,258
243	Gross Operating Costs %								Allocation %	62.4%	10.5%	27.2%
244		Other Revenues										
245	All	Interest Revenues		($1,252,400)	62.3%	10.4%	27.2%	Calculation	Operating Costs	$ (780,857)	($130,686)	($340,857)
246	All	SC Application and Training Fees		($120,000)	62.3%	10.4%	27.2%	Calculation	Operating Costs	$ (74,819)	($12,522)	($32,660)
247	All	WSCC Security Coordination		($1,255,891)	100.0%	0.0%	0.0%	Finance	Direct Assignment	$ (1,255,891)	$0	$0
248	Total Other Revenue			($2,628,291)						$ (2,111,567)	$ (143,208)	$ (373,517)
249	Total Other Revenue %								Allocation %	80.3%	5.4%	14.2%
250		Net Operating Costs										
251	Total Salaries		$ 77,558,029							48,716,081	8,576,384	20,265,564

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CALIFORNIA ISO
COST ALLOCATION MATRIX - 2003 BUDGET

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Line #	ISO Dept #	OPERATING COSTS	Amount Labor	Amount Total Costs	Allocation: Control Area Services	Allocation: Congestion Mgmt.	Allocation: ASREO/MO	Source	Allocation/ Assignment Method	Total Costs Assigned/Allocated: Control Area Services	Total Costs Assigned/Allocated: Congestion Mgmt.	Total Costs Assigned/Allocated: ASREO/MO
252	**Total Salaries %**								**Allocation %**	62.8%	11.1%	26.1%
253	**Net Operating Costs**			**$169,110,838**						$104,993,900	$17,815,196	$46,301,742
254	**Net Operating Costs %**								**Allocation %**	62.1%	10.5%	27.4%
255		**1998 Bonds**										
256		**Infrastructure - Direct Assigned Items**										
257		EMS		$16,470,000	100.0%	0.0%	0.0%	Contract/ Functional Anal.	Direct Assignment	$16,470,000	$0	$0
258		SI		$27,102,000	39.0%	20.0%	41.0%	Contract/ Functional Anal.	Direct Assignment	$10,569,780	$5,420,400	$11,111,820
259		SA		$31,681,000	35.0%	25.0%	40.0%	Contract/ Functional Anal.	Direct Assignment	$11,088,350	$7,920,250	$12,672,400
260		BBS (Billing & Settlements)		$48,173,000	15.0%	7.0%	78.0%	Contract/ Functional Anal.	Direct Assignment	$7,225,950	$3,372,110	$37,574,940
261		MDAS (Metering)		$8,166,000	30.0%	8.0%	62.0%	Contract/ Functional Anal.	Direct Assignment	$2,449,800	$653,280	$5,062,920
262		RMR-Software		$56,000	100.0%	0.0%	0.0%	Contract/ Functional Anal.	Direct Assignment	$56,000	$0	$0
263		Market Anaysis Software		$238,000	0.0%	0.0%	100.0%	Contract/ Functional Anal.	Direct Assignment	$0	$0	$238,000
264		Vehicles MDAS/Metering		$96,000	30.0%	8.0%	62.0%	Contract/ Functional Anal.	Direct Assignment	$28,800	$7,680	$59,520
265		FERC Study Software		$11,000	25.0%	25.0%	50.0%	Contract/ Functional Anal.	Direct Assignment	$2,750	$2,750	$5,500
266		GCP/RIG (Generator Communication with IS		$975,000	100.0%	0.0%	0.0%	Contract/ Functional Anal.	Direct Assignment	$975,000	$0	$0
267		SRS Software (FTR related)		$1,049,000	10.0%	75.0%	15.0%	Contract/ Functional Anal.	Direct Assignment	$104,900	$786,750	$157,350
268		ETC Software		$891,000	100.0%	0.0%	0.0%	Contract/ Functional Anal.	Direct Assignment	$891,000	$0	$0
269		FTR Auction software		$17,000	10.0%	75.0%	15.0%	Contract/ Functional Anal.	Direct Assignment	$1,700	$12,750	$2,550
270		ACC Upgrades (Communication btw ISO and		$1,162,000	100.0%	0.0%	0.0%	Contract/ Functional Anal.	Direct Assignment	$1,162,000	$0	$0
271		**Total Infrastructure Direct Assigned Items**		**$136,087,000**						$51,026,030	$18,175,970	$66,885,000
272		**Infrastructure - Allocated Items**										
273		Issue Management System -Remedy		$692,000	62.1%	10.5%	27.4%	Calculation	Operating Costs	$429,634	$72,900	$189,466
274		Security System - CUDA		$6,993,000	62.1%	10.5%	27.4%	Calculation	Operating Costs	$4,341,663	$736,686	$1,914,650
275		Corporate Accounting - Oracle		$2,993,000	62.1%	10.5%	27.4%	Calculation	Operating Costs	$1,858,229	$315,301	$819,469
276		Document Management System - EDMS		$1,715,000	62.1%	10.5%	27.4%	Calculation	Operating Costs	$1,064,772	$180,669	$469,559
277		HR System - Imperativ		$136,000	62.1%	10.5%	27.4%	Calculation	Operating Costs	$84,437	$14,327	$37,236
278		HR System - ABRA		$38,000	62.1%	10.5%	27.4%	Calculation	Operating Costs	$23,593	$4,003	$10,404
279		System Management and Monitoring - Tivoli		$200,000	62.1%	10.5%	27.4%	Calculation	Operating Costs	$124,172	$21,069	$54,759
280		Data Warehouse		$1,279,000	62.1%	10.5%	27.4%	Calculation	Operating Costs	$794,078	$134,738	$350,184
281		Network Software		$630,000	62.1%	10.5%	27.4%	Calculation	Operating Costs	$391,141	$66,368	$172,491
282		Facilities		$10,566,000	62.8%	11.1%	26.1%	Calculation	Labor Dollar Ratios	$6,636,761	$1,168,391	$2,760,848
283		Furniture		$5,391,000	62.8%	11.1%	26.1%	Calculation	Labor Dollar Ratios	$3,386,218	$596,138	$1,408,644
284		Facilities-Office Equipment		$1,330,000	62.8%	11.1%	26.1%	Calculation	Labor Dollar Ratios	$835,405	$147,072	$347,523
285		Transmission Display Software - TIDS		$139,000	62.1%	10.5%	27.4%	Calculation	Operating Costs	$86,299	$14,643	$38,058
286		Other software and Enhancements		$3,482,000	62.1%	10.5%	27.4%	Calculation	Operating Costs	$2,161,829	$366,816	$953,355
287		MCI Contract		$27,040,000	60.1%	10.7%	29.2%	Calculation	Telecom Dept	$16,243,846	$2,892,060	$7,904,094
288		IBM Contract		$6,816,000	60.7%	10.0%	29.2%	Calculation	IT Dept	$4,140,503	$682,688	$1,992,809
289		**Total Infrastructure Allocated Items**		**$69,440,000**						$42,602,582	$7,413,869	$19,423,549
290		**Subtotal Infrastructure**		**$205,527,000**						$93,628,612	$25,589,839	$86,308,549
291		**Subtotal Infrastructure %**							**Allocation %**	45.6%	12.5%	42.0%

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CALIFORNIA ISO
COST ALLOCATION MATRIX - 2003 BUDGET

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Line #	ISO Dept #	OPERATING COSTS	Amount Labor	Amount Total Costs	Allocation			Source	Allocation/ Assignment Method	Total Costs Assigned/Allocated		
					Control Area Services	Congestion Mgmt.	ASREO/MO			Control Area Services	Congestion Mgmt.	ASREO/MO
292		**Startup - Allocated Items**										
293		Trustee Costs		$5,692,000	45.6%	12.5%	42.0%	Calculation	Infrastructure subtotal	$2,593,012	$708,702	$2,390,286
294		Interest-Capitalized		$1,261,000	45.6%	12.5%	42.0%	Calculation	Infrastructure subtotal	$574,453	$157,005	$529,542
295		User Groups		$957,000	45.6%	12.5%	42.0%	Calculation	Infrastructure subtotal	$435,965	$119,155	$401,880
296		Startup Costs-through 3/31/98		$52,897,000	62.1%	10.5%	27.4%	Calculation	Operating Costs	$32,841,552	$5,572,502	$14,482,947
297		Working Capital-3 months		$21,692,000	62.1%	10.5%	27.4%	Calculation	Operating Costs	$13,467,662	$2,285,171	$5,939,166
298		**Total Startup Allocated Items**		**$82,499,000**						$49,912,645	$8,842,534	$23,743,821
299		**Other Software and Enhancements**										
300		2000 Spending: EMS/MDAS/Participating Lo		$1,651,155	91.5%	1.0%	7.5%	Contract/ Functional Anal.	Direct Assignment	$1,511,467	$16,016	$123,672
301		2000 Spending: SA/SI/BBS		$4,569,322	22.9%	51.6%	25.4%	Contract/ Functional Anal.	Direct Assignment	$1,047,746	$2,359,598	$1,161,979
302		2000 Spending: Other Systems/Vehicles		$1,240,714	12.7%	0.7%	86.6%	Contract/ Functional Anal.	Direct Assignment	$157,198	$8,561	$1,074,955
303		2001 Spending: Other Systems		$4,439,568	62.1%	10.5%	27.4%	Calculation	Operating Costs	$2,756,344	$467,692	$1,215,533
304		2000 Spending: Facilities/Furniture/Office Eq		$1,473,241	62.8%	11.1%	26.1%	Calculation	Labor Dollar Ratios	$925,378	$162,911	$384,951
305		**Total Other Software and Enhancements**		**$13,374,000**						$6,398,133	$3,014,778	$3,961,089
306		**Total 1998 Bonds**										
307	**Total 1998 Bonds**			**$301,400,000**						$149,939,390	$37,447,152	$114,013,458
308	**Total 1998 Bonds %**								**Allocation %**	49.7%	12.4%	37.8%
309		**Total 2000 Bonds**										
310		Land & Building Costs		$9,300,000	62.8%	11.1%	26.1%	Calculation	Labor Dollar Ratios	$5,841,556	$1,028,396	$2,430,048
311		2000 Spending:SA/SI/BBS		$15,233,506	49.3%	0.5%	50.1%	Contract/ Functional Anal.	Direct Assignment	$7,514,689	$82,261	$7,636,557
312		2000 Spending: EMS/CIM/FDA		$1,435,154	83.1%	1.9%	15.0%	Contract/ Functional Anal.	Direct Assignment	$1,191,895	$27,842	$215,417
313		2000 Spending: Other Systems		$4,000,555	62.1%	10.5%	27.4%	Calculation	Operating Costs	$2,483,779	$421,444	$1,095,333
314		2001 Spending: EMS		$5,286,679	100.0%	0.0%	0.0%	Contract/ Functional Anal.	Direct Assignment	$5,286,679	$0	$0
315		2001 Spending: SA/SI/BBS		$844,106	40.1%	0.0%	59.9%	Contract/ Functional Anal.	Direct Assignment	$338,824	$0	$505,282
316	**Total 2000 Bonds**			**$36,100,000**						$22,657,421	$1,559,943	$11,882,636
317	**Total 2000 Bonds %**								**Allocation %**	62.8%	4.3%	32.9%
318		**Total 1998 and 2000 Bonds**										
319	**Total 1998 and 2000 Bonds**			**$337,500,000**						$172,596,811	$39,007,094	$125,896,094
320	**Total 1998 and 2000 Bonds %**								**Allocation %**	51.1%	11.6%	37.3%
321		**Total Debt Service**										
322	Debt Service - Existing Debt (1998 and 2000 Bonds): Inc			$54,746,238	51.1%	11.6%	37.3%	Calculation	1998 & 2000 bonds	$27,997,114	$6,327,383	$20,421,741
323												
324	**Total Debt Service Cost**			**$54,746,238**						**$27,997,114**	**$6,327,383**	**$20,421,741**
325	**Total Debt Service Cost %**								**Allocation %**	51.1%	11.6%	37.3%
326		**Cash Funded Cap Ex: 2003 Capital Budget**										
327		2003 Budget: Operating Systems		$3,193,000	60.4%	7.9%	31.7%	Contract/ Functional Anal.	Direct Assignment	$1,928,253	$253,205	$1,011,542
328		2003 Budget: Furniture/Facilities/Office Equi		$445,000	62.8%	11.1%	26.1%	Calculation	Labor Dollar Ratios	$279,515	$49,208	$116,276
329		2003 Budget: Corporate Systems		$3,320,000	62.1%	10.5%	27.4%	Calculation	Operating Costs	$2,061,250	$349,750	$909,000
330		2003 Budget: MD02		$15,042,000	32.0%	33.0%	35.0%	Contract/ Functional Anal.	Direct Assignment	$4,813,440	$4,963,860	$5,264,700
331	**Total Cash Funded Cap Ex**			**$22,000,000**						**$9,082,458**	**$5,616,023**	**$7,301,519**
332	**Total Cash Funded Cap Ex%**								Allocation %	41.3%	25.5%	33.2%
333		**Total Cost of Service - 2003**								100.0%		
334	**Gross O&M Costs**		$ 77,558,029	$171,739,129	62.1%	10.5%	27.4%			$107,105,467	$17,958,404	$46,675,258
335	**Other Costs and Income**			($2,628,291)	80.3%	5.4%	14.2%			$ (2,111,567)	$ (143,208)	$ (373,517)
336	**Net O&M Costs**			$169,110,838	62.4%	10.5%	27.2%			$104,993,900	$17,815,196	$46,301,742
337	**Debt Service**			$54,746,238	51.1%	11.6%	37.3%			$27,997,114	$6,327,383	$20,421,741

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CALIFORNIA ISO
COST ALLOCATION MATRIX - 2003 BUDGET

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Line #	ISO Dept #	OPERATING COSTS	Amount Labor	Amount Total Costs	Allocation			Source	Allocation/ Assignment Method	Total Costs Assigned/Allocated		
					Control Area Services	Congestion Mgmt.	ASREO/MO			Control Area Services	Congestion Mgmt.	ASREO/MO
338	Cash Funded Cap Ex			$22,000,000	41.3%	25.5%	33.2%			$9,082,458	$5,616,023	$7,301,519
339	**Total Cost of Service: Prior to Op. Reserve**			**$245,857,076**						**$142,073,473**	**$29,758,602**	**$74,025,002**
340	**Total Cost of Service %**								**Allocation % results before Revenue Credit or Deficiency**	57.8%	12.1%	30.1%
341	**(Revenue Credit)/Shortfall**			$ (8,256,705)	51.1%	28.6%	20.4%			$ (4,216,604)	$ (2,358,081)	$ (1,682,020)
342	**Total Cost of Service**			**$237,600,371**						**$137,856,869**	**$27,400,520**	**$72,342,981**
343	**Total Cost of Service %**								**Net Allocation %**	58.0%	11.5%	30.4%

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COST ALLOCATION MATRIX - 2003 BUDGET

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DRAFT: SUBJECT

Line #	ISO Dept #	OPERATING COSTS	Amount Labor	Amount Total Costs	FTE from Budget	Allocation: Control Area Services	Allocation: Dynamic Dispatch Export Service	Allocation: Scheduling Service	Allocation: Market Operations Service	Allocation: Real Time Market Operations Service	Check	Allocation/ Assignment Method	Total Costs Assigned/A: Control Area Services	Total Costs Assigned/A: Dynamic Dispatch Export Service	Total Costs Assigned/A: Scheduling Service
1	1500	Operations - Direct Costs													
2	1521	Grid Planning	$ 2,041,338		15						To Assess	Direct Assignment	$ 2,425,338	$ -	$ -
3		Total Costs		$ 2,425,338											
4	1542	Outage Coordination	$ 1,580,356		12						To Assess	Direct Assignment	$ 1,780,930	$ -	$0
5		Total Costs		$ 1,780,930											
6	1543	Loads and Resources	$ 943,936		7						To Assess	Direct Assignment	$ 1,006,436	$ -	$ -
7		Total Costs		$ 1,006,436											
8	1544	Real-Time Scheduling	$ 2,578,768		20						To Assess	Direct Assignment	$ 2,278,823	$ -	$134,048
9		Total Costs		$ 2,680,968											
10	1545	Grid Operations - General	$ 6,844,825		51						To Assess	Direct Assignment	$ 5,733,860	$ -	$0
11		Total Costs		$ 7,167,325											
12	1546	Security Coordination	$ 1,207,891		8						To Assess	Direct Assignment	$ 1,255,891	$ -	$0
13		Total Costs		$ 1,255,891											
14	1554	Special Projects Engineer	$ 601,931		4						To Assess	Direct Assignment	$ 774,883	$ -	$0
15		Total Costs		$ 860,981											
16	1555	Operations Support Group	$ 974,683		9						To Assess	Direct Assignment	$ 1,025,163	$ -	$0
17		Total Costs		$ 1,025,163											
18	1558	Transmission Maintenanc	$ 1,141,103		8						To Assess	Direct Assignment	$ 1,804,953	$ -	$0
19		Total Costs		$ 1,804,953											
20	1561	Operations Engineering S	$ 1,034,681		7.5						To Assess	Direct Assignment	$ 1,240,187	$ -	$0
21		Total Costs		$ 1,240,187											
22	1562	Operations Engineering N	$ 1,168,863		8						To Assess	Direct Assignment	$ 1,226,703	$ -	$0
23		Total Costs		$ 1,226,703											
24	1563	Coordinated Operations	$ 584,551		4						To Assess	Direct Assignment	$ 542,361	$ -	$0
25		Total Costs		$ 677,951											
26	1565	Pre-Scheduling and Supp	$ 1,660,765		13						To Assess	Direct Assignment	$ 1,527,629	$ -	$84,868
27		Total Costs		$ 1,697,365											
28	1566	Regional Coordination - G	$ 423,012		3						To Assess	Direct Assignment	$ 554,912	$ -	$0
29		Total Costs		$ 554,912											

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CALIFORNIA ISO
COST ALLOCATION MATRIX - 2003 BUDGET

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DRAFT: SUBJECT

Line #	ISO Dept #	OPERATING COSTS	Amount Labor	Amount Total Costs	FTE from Budget	Allocation: Control Area Services	Allocation: Dynamic Dispatch Export Service	Allocation: Scheduling Service	Allocation: Market Operations Service	Allocation: Real Time Market Operations Service	Check	Allocation/ Assignment Method	Total Costs Assigned/A: Control Area Services	Total Costs Assigned/A: Dynamic Dispatch Export Service	Total Costs Assigned/A: Scheduling Service
30	~~1549~~	~~Operations Training~~	~~$ 1,919,268~~		20										
31		Total Costs		$ 3,064,253							To Assess	Direct Assignment	$ 1,991,764	$ -	$459,638
32	1559	Operations Application Su	$ 447,958		4										
33				$ 458,472							To Assess	Direct Assignment	$ 412,625	$ -	$0
34	**Total Operations Direct Salary Cost C**		**$ 25,153,929**												
35	**Total Operations Direct Salary %**												$ 25,582,457	$ -	$ 678,555
36	**Total Operations Direct Costs**			**$ 28,927,828**											
37	**Total Operations Direct Costs %**											**Allocation %**	88.4%	0.0%	2.3%
38	**1500**	**Operations - Indirect Costs**													
39	1511	VP Grid Operations - Gen	$ 365,202		1.5										
40		Total		$ 1,011,957		87.8%	0.0%	2.5%	4.8%	4.9%	Calculation	Allocated based on Department Direct Costs	$ 888,733	$ -	$ 25,564
41	1547	Engineering and Maintena	$ 289,222		3										
42		Total Costs		$ 1,154,222		100.0%	0.0%	0.0%	0.0%	0.0%	Calculation	Allocated based on Supervised Departments costs	$ 1,154,222	$ -	$ -
43	1548	OSAT	$ 182,432		1										
44		Total Costs		$ 267,932		76.0%	0.0%	8.8%	12.3%	2.9%	Calculation	Allocated based on Supervised Departments costs	$ 203,642	$ -	$ 23,566
45	1564	Operations Scheduling - C	$ 281,362		3										
46		Total Costs		$ 322,862		90.7%	0.0%	3.6%	3.6%	2.2%	Calculation	Allocated based on Supervised Departments costs	$ 292,885	$ -	$11,475
47	**Total Operations Indirect Salaries**		**$ 1,118,218**												
48	**Total Operations Indirect Costs**			**$ 2,756,973**									$ 2,539,482	$ -	$ 60,606
49	**Total Operations Salaries**		**$ 26,272,147**												
50	**Total Operations Costs**			**$ 31,684,801**									$ 28,121,939	$ -	$ 739,160
51	**Operations Indirect Costs as % of Total**			9%											
52	**1700**	**VP Market Services**													
53	1722	Application Support	$ 414,256		4										
54		Total Costs		$ 510,466							To Assess	Direct Assignment	$ 127,617	$ -	$ 127,617
55	1723	Tariff and Contract Implen	$ 667,205		7										
56		Total Costs		$ 896,883							To Assess	Direct Assignment	$ 896,883	$ -	$ -

CALIFORNIA ISO
COST ALLOCATION MATRIX - 2003 BUDGET

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Appendix C2

DRAFT: SUBJECT

Line #	ISO Dept #	OPERATING COSTS	Amount Labor	Amount Total Costs	FTE from Budget	Allocation: Control Area Services	Allocation: Dynamic Dispatch Export Service	Allocation: Scheduling Service	Allocation: Market Operations Service	Allocation: Real Time Market Operations Service	Check	Allocation/ Assignment Method	Total Costs Assigned/A: Control Area Services	Total Costs Assigned/A: Dynamic Dispatch Export Service	Total Costs Assigned/A: Scheduling Service
57															
58	1724	BBS - PSS	$ 942,333		9										
59		Total Costs		$ 1,148,361		[redacted]					To Assess	Direct Assignment	$ 287,090	$ -	$ 287,090
60	1725	BBS - FSS	$ 1,037,777		10										
61		Total Costs		$ 1,280,321		[redacted]					To Assess	Direct Assignment	$ 320,080	$ -	$ 320,080
62	1731	Contracts and Special Pro	$ 1,153,955		9										
63		Total Costs		$ 1,439,963		[redacted]					To Assess	Direct Assignment	$ 1,439,963	$ -	$ -
64	1741	Client Relations	$ 2,054,540		19										
65		Total Costs		$ 2,299,956		[redacted]					To Assess	Direct Assignment	$ 574,989	$ -	$ 574,989
66	1752	Manager of Markets	$ 2,156,353		17										
67		Total Costs		$ 2,355,353		[redacted]					To Assess	Direct Assignment	$ 706,606	$ -	$ -
68	1753	Market Engineering	$ 1,680,883		13										
69		Total Costs		$ 2,061,799		[redacted]					To Assess	Direct Assignment	$ -	$ -	$ -
70	1755	Business Solutions	$ 739,166		5										
71		Total Costs		$ 942,745		[redacted]					To Assess	Direct Assignment	$ -	$ -	$ -
72	1756	Market Quality - General	$ 1,940,408		18										
73		Total Costs		$ 2,102,565		[redacted]					To Assess	Direct Assignment	$ -	$ -	$ -
74	1757	Market Integration	$ 587,361		5										
75				$ 835,895		[redacted]					To Assess	Direct Assignment	$ -	$ -	$ -
76	**Total Market Services Direct Salaries**		**$13,374,237**												
77	**Total Market Services Direct Salaries %**														
78	**Total Market Services Direct Costs**			**$15,874,307**											
79	**Total Market Services Direct Costs %**											**Allocation %**	4,353,228 27.4%	- 0.0%	1,309,776 8.3%

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DRAFT: SUBJECT

Line #	ISO Dept #	OPERATING COSTS	Amount Labor	Amount Total Costs	FTE from Budget	Allocation: Control Area Services	Allocation: Dynamic Dispatch Export Service	Allocation: Scheduling Service	Allocation: Market Operations Service	Allocation: Real Time Market Operations Service	Check	Allocation/ Assignment Method	Total Costs Assigned/A: Control Area Services	Total Costs Assigned/A: Dynamic Dispatch Export Service	Total Costs Assigned/A: Scheduling Service
80	1700	Market Services - Indirect Costs													
81	1711	VP Market Services - Gen	$ 394,287		2										
82		Total		$ 248,117		27.4%	0.0%	8.3%	45.6%	18.7%	Calculation	Allocated based on Department Direct Costs	68,041	-	20,472
83	1721	Billing and Settlements-G	$ 347,911		2										
84		Total Costs		$ 353,911		42.5%	0.0%	19.2%	19.2%	19.2%	Calculation	Allocated based on Supervised Departments costs	$ 150,537	$ -	$ 67,791
85	1751	Market Operations - Gene	$ 331,747		3										
86		Total Costs		$ 959,968		11.4%	0.0%	0.0%	68.6%	20.0%	Calculation	Allocated based on Supervised Departments	$ 109,481	$ -	$ -
87	**Total Market Services Indirect Salarie**		**$ 1,073,945**										328,059	-	88,263
88	**Total Market Services Indirect Costs**			**$ 1,561,996**											
89	**Total Market Services Salaries**		**14,448,182**										4,681,287	-	1,398,039
90	**Total Market Services Costs**			**$17,436,303**									26.85%	0.00%	8.02%
91	**Market Services Indirect as % of Total**			9%											
92	1400	Information Services - Direct Costs													
93	1424	Asset Management	$ 845,319		8										
94		Total Costs		$ 21,742,188							To assess	Direct Assignment	$ 20,002,813	$ -	$0
95	1441	Outsourced Contracts	$ 159,466		2										
96		Total Costs		$ 29,683,478							To assess	To be further considered- may use allocation approach.	$ 26,715,130	$ -	$0
97	1461	Control Systems	$ 2,186,977		19										
98		Total Costs		$ 2,321,654							To assess	Direct Assignment	$ 2,321,654	$ -	$0
99	1462	Field Data Acquisition Sys	$ 1,805,783		15										
100		Total Costs		$ 2,508,556							To assess	Direct Assignment	$ 2,508,556	$ -	$0
101	1467	Settlement Systems Servi	$ 980,615		9										
102		Total Costs		$ 1,064,350							To assess	Direct Assignment	$ 266,088	$ -	$266,088
103	**Total IS Direct Salaries**		**$ 5,978,160**										$ -	$ -	$ -
104	**Total IS Direct Salaries %**											**Allocation %**	0.0%	0.0%	0.0%
105	**Total IS Direct Costs**			**$ 57,320,226**									$ 51,814,241	$ -	$ 266,088
106	**Total IS Direct Cost %**											**Allocation %**	90.39%	0.00%	0.46%
107	1600	Legal - Direct Costs													
108	1641	Market Analysis	$ 1,997,346		16										
109		Total		$ 3,053,880							Department	Direct Assignment	$ -	$ -	$ -
110	1642	Market Surveillance Comr	$ -		0								$ -	$ -	$ -
111		Total		$ 640,750							Department	Direct Assignment	$ -	$ -	$ -
112	1661	Compliance - General	$ 1,150,095		10										

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113				$ 1,456,895							Department	Direct Assignment	$ 582,758	$ -	$ 582,758
114	1662	Compliance - Audits	$ 357,191		3										
115		Total Costs		$ 416,191							Department	Direct Assignment	$ -	$ -	$ 137,343
116	**Total Legal Direct Salaries**		**$ 3,504,632**												
117	**Total Legal Direct Salaries %**												$ 582,758	$ -	$ 720,101
118	**Total Legal Direct Costs**			**$ 5,567,716**								**Allocation %**	10.5%	0.0%	12.9%
119	**Total Legal Direct Cost %**														
120	**Subtotal Salaries Operations, Market Services, Indirec**			**$ 50,203,121**											
121	**Salary Percentages**												$ 85,200,225	$ -	$ 3,123,388
122	**Subtotal Costs Operations, Market Services, Indirect I**			**$ 112,009,046**									76.1%	0.0%	2.8%
123	**Expense Percentages**														
124	1400	VP Information Services Indirect Costs													
125	1411	Chief Information Officer-	$ 391,143		2										
126		Total		$ 212,246		90.4%	0.0%	0.5%	6.4%	2.8%	Calculation	Allocated based on Department Direct Costs	$ 191,858	$ -	$985
127	1422	Corporate & Enterprise Ap	$ 233,320		2										
128		Total Costs		$ 248,320		76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	Allocated based on Supervised Departments costs	$ 188,886	$ -	$ 6,924
129	1466	Enterprise Applications	$ 764,123		6										
130		Total Costs		$ 816,499		76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	Allocated based on Direct Operating Costs	$ 621,074	$ -	$ 22,768
131	1431	End User Support	$ 491,206		4										
132		Total Costs		$ 6,565,001		76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	Allocated based on Direct Operating Costs	$ 4,993,700	$ -	$183,066
133	1432	Computer Operations - Ge	$ 403,068		3										
134		Total Costs		$ 430,975		76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	Allocated based on Supervised Departments costs	$ 327,823	$ -	$12,018
135	1433	Network Operations	$ 1,549,597		12										
136		Total Costs		$ 1,629,905		76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	Allocated based on Direct Operating Costs	$ 1,239,795	$ -	$45,450

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DRAFT: SUBJECT

Line #	ISO Dept #	OPERATING COSTS	Amount Labor	Amount Total Costs	FTE from Budget	Allocation: Control Area Services	Allocation: Dynamic Dispatch Export Service	Allocation: Scheduling Service	Allocation: Market Operations Service	Allocation: Real Time Market Operations Service	Check	Allocation/ Assignment Method	Total Costs Assigned/A: Control Area Services	Total Costs Assigned/A: Dynamic Dispatch Export Service	Total Costs Assigned/A: Scheduling Service
137	1442	Production Support	$ 2,440,565		18										
138		Total Costs		$ 2,581,165		76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	Allocated based on Direct Operating Costs	$ 1,963,376	$ -	$71,976
139	1451	Information Security	$ 1,038,281		9										
140		Total Costs		$ 1,509,500		76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	Allocated based on Direct Operating Costs	$ 1,148,209	$ -	$42,093
141	1463	Operations Applications -	$ 292,237		3										
142		Total Costs		$ 323,539		84.3%	0.0%	4.2%	6.6%	4.9%	Calculation	Allocated based on Supervised Departments costs	$ 272,829	$ -	$13,460
143	1471	IT Planning	$ 628,349		5										
144		Total Costs		$ 770,116		76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	Allocated based on Direct Operating Costs	$ 585,792	$ -	$21,475
145	1468	Corporate Application Sup	$ 1,188,702		9										
146				$ 1,333,287		76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	Allocated based on Direct Operating Costs	$ 1,014,171	$ -	$37,179
147	1469	Analytical and Reporting	$ 984,106		8										
148				$ 1,055,106		76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	Allocated based on Direct Operating Costs	$ 802,572	$ -	$29,422
149	1481	Markets and Scheduling	$ 1,267,761		10										
150		Total Costs		$ 1,520,628		76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	Allocated based on Direct Operating Costs	$ 1,156,673	$ -	$42,403
151	**Total IS Indirect Salaries**		**$ 11,672,458**												
152	**Total IS Indirect Costs**			**$ 18,996,287**									$ 14,506,758	$ -	$ 529,219
153	**Total IS Operating Salaries**		**$ 17,650,618**												
154	**Total IS Operating Costs**			**$76,316,513**									$ 66,320,999	$ -	$ 795,306
155	**IS Indirect Costs as % of IT Operating Costs**			25%											
156	**Operating Costs and Salaries Before Corporate Indirects**														
157	**Total Operating Salaries**		**$ 61,875,579**												
158	**Total Operating Salaries %**														

CALIFORNIA ISO
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Line #	ISO Dept #	OPERATING COSTS	Amount Labor	Amount Total Costs	FTE from Budget	Allocation: Control Area Services	Allocation: Dynamic Dispatch Export Service	Allocation: Scheduling Service	Allocation: Market Operations Service	Allocation: Real Time Market Operations Service	Check	Allocation/ Assignment Method	Total Costs Assigned/A: Control Area Services	Total Costs Assigned/A: Dynamic Dispatch Export Service	Total Costs Assigned/A: Scheduling Service
159	**Total Operating Costs**			**$131,005,333**									**$99,706,983**	**$0**	**$3,652,607**
160	**Total Operating Costs %**											**Allocation %**	76.1%	0.0%	2.8%
161	**1300**	**Finance - Corporate Indirect Costs**													
162	1321	Accounting	$ 836,830		9.5										
163		Total		$ 2,168,530		76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	Allocated based on Direct Operating Costs	$ 1,650,449	$ -	$ 60,462
164	1331	Financial Planning and Tr	$ 714,782		6.5										
165		Total		$ 2,511,009		76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	Allocated based on Direct Operating Costs	$ 1,911,106	$ -	$ 70,010
166	1351	Facilities	$ 641,351		7										
167		Total		$ 5,812,962		76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	Allocated based on Direct Operating Costs	$ 4,424,193	$ -	$ 162,073
168	1361	Office Administration	$ 643,601		10										
169		Total		$ 2,227,171		76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	Allocated based on Direct Operating Costs	$ 1,695,080	$ -	$ 62,097
170	**Total Finance Indirect Costs**			**$12,719,672**									$ 9,680,828	$ -	$ 354,642
171	**Total Finance Op Salaries b/f CFO**		**$ 2,836,564**												
172	**Finance Indirect as % of Fin Operating Costs**			100%									76.1%	0.0%	2.8%
173	**1300**	**Finance - Based on Finance Corporate Indirect Costs**													
174															
175	1311	CFO - General	$ 420,090		1.5										
176		Total		$ 424,204		76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	Allocated based on Supervised Departments costs	$ 322,858	$ -	$ 11,827
177	**Total Finance Op Salaries**		**$ 3,256,654**										$ -	$ -	$ -
178	**Total Finance Operating Costs**			**$ 13,143,876**									$ 10,003,686	$ -	$ 366,469
179	**Finance Indirect as % of Fin Operating Costs**			100%											
180	**1600**	**Legal: Chief Counsel - Corporate Indirect Costs**													
181	1631	Legal and Regulatory	$ 3,330,071		23										
182		Total		$ 13,118,010		76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	Allocated based on Direct Operating Costs	$ 9,984,000	$ -	$365,748
183	**Total Legal Indirect Salaries**		**$ 3,330,071**												
184	**Total Legal Indirect Costs**			**$ 13,118,010**									$ 9,984,000	$ -	$ 365,748
185	**Total Legal Salaries**		**$ 6,834,703**												
186	**Total Legal Costs**			**$18,685,726**									$10,566,758	$0	$1,085,849
187	**Indirect as % of Total**			70.2%									56.5%	0.0%	5.8%
188	**1600**	**Legal: Chief Counsel - Based on Legal Corporate Indirect and**													

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189	1611	VP General Counsel - Ge	$ 468,583		2										
190		Total		$ 385,985		58.7%	0.0%	6.0%	26.5%	8.8%	Calculation	Allocated based on Supervised Departments costs	$ 226,632	$ -	$23,115
180	**Total Legal Salaries**		**$ 7,303,286**										$10,793,389	$0	$1,108,964
191	**Total Legal Costs**			**$19,071,711**											
191	**Indirect as % of Total**			72%								Op Cost %	56.6%	0.0%	5.8%
192	**1800**	**VP Corporate and Strategic Development - Corporate Indirect**													
193	1821	Communications	$ 452,711		4										
194		Total Costs		$ 865,811		76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	Allocated based on Direct Operating Costs	$ 658,961	$ -	$ 24,140
195	1831	Strategic Development	$ 477,745		3										
196				$ 693,745		76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	Allocated based on Direct Operating Costs	$ 528,003	$ -	$ 19,343
197	1851	Project Office	$ 583,258		4										
198				$ 657,758		76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	Allocated based on Direct Operating Costs	$ 500,614	$ -	$ 18,339
199	1861	Regulatory Policy	$ 585,142		4										
200		Total Costs		$ 1,430,767		76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	Allocated based on Direct Operating Costs	$ 1,088,944	$ -	$ 39,892
201	**Total Corporate and Strategic Devpt**		**$ 2,098,856**										$ 2,776,522	$ -	$ 101,713
202	**Total Corporate and Strategic Devpt b/f HR**			**$3,648,081**											
203												Op Cost %	**76.1%**	**0.0%**	**2.8%**
204	**1800**	**VP Corporate and Strategic Development - Based on Corporat**													
205	1811	VP Corporate and Strateg	$ 392,226		2										
206		Total Costs		$ 497,434		76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	Allocated based on Supervised Departments costs	$ 378,593	$ -	$ 13,869
207	**Total Corporate and Strategic Devt b.**		**$ 2,491,082**										$ 3,155,114	$ -	$ 115,583
208	**Total Corporate and Strategic Devt b/f HR**			**$4,145,515**									76.1%	0.0%	2.8%
209	**Cost Allocation Percentage**														
210	**1241**	**MD02**													
211	1241	MD02	$ 882,609		6										
212		Total Costs		$ 909,609		60.0%	0.0%	20.0%	15.0%	5.0%	To assess	Direct Assignment	$ 545,765	$ -	$ 181,922
213	MD02		**$ 882,609**												

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214				$ 909,609									$ 545,765	$ -	$ 181,922
215		**Cost Allocation Percentage**											60.0%	0.0%	20.0%
216															
217		**Total Costs and Salaries before HR/CEO**													
218		**Total Costs and Salaries before HR/CEO**													
219		**Total Salaries before HR/CEO**	$ 72,304,578												
220		**Total Salaries before HR/CEO %**													
221		**Total Costs before HR/CEO**		$ 162,708,328									$ 123,622,180	$ -	$ 4,705,443
222		**Total Costs before HR/CEO %**										**Allocation %**	76.0%	0.0%	2.9%
223		**1100/1200 CEO / Human Resources - Corporate Indirects**													
224	1111	CEO - General	$ 744,874		2	76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	Allocated based on Direct Operating Costs	$ 556,281	$ -	$ 20,378
225		Total		$ 730,899											
226	1841	Human Resources	$ 1,166,617		13	76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	Allocated based on Direct Operating Costs	$ 3,649,311	$ -	$ 133,687
227		Total		$ 4,794,842											
228	1651	Board of Governors			0	76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	Allocated based on Direct Operating Costs	$ 124,134	$ -	$ 4,547
229		Total		$ 163,100											
230		**Total CEO/HR Salaries**	**$ 1,911,491**										$ 4,329,726	$ -	$ 158,613
231		**Total CEO/HR Costs**		**$ 5,688,841**											
232		**Total Salaries Prior to Salary Adjustn**	**$ 74,216,069**												
233		**Total Salaries Prior to Salary Adjustments %**													
234		**Total Costs Prior to Salary Adjustments**		**168,397,169**									$ 127,951,906	$ -	$ 4,864,056
235		**Total Costs Prior to Salary Adjustments &**										**Allocation %**	76.0%	0.0%	2.9%
236		**Other Costs**													
237	All	**Salary Adjustments, next**	$ 3,341,960	$3,341,960		76.0%	0.0%	2.9%	14.7%	6.4%	Calculation	Total Costs Prior to Salary Adjustment	2,539,295	-	96,531
238		**Total Other Costs**	**$ 3,341,960**	**$3,341,960**									$2,539,295	$0	$96,531
239		**Gross Operating Costs**													
240		**Total Operating Salaries**	**$ 77,558,029**												
241		**Total Operating Salaries %**													
242		**Gross Operating Costs**		**$171,739,129**									**$130,491,202**	**$0**	**$4,960,586**
243		**Gross Operating Costs %**										**Allocation %**	76.0%	0.0%	2.9%
244		**Other Revenues**													
245	All	Interest Revenues		($1,252,400)		76.0%	0.0%	2.9%	14.7%	6.4%	Calculation	Operating Costs	$ (951,546)	$ -	($36,219)
246	All	SC Application and Training Fees		($120,000)		76.0%	0.0%	2.9%	14.7%	6.4%	Calculation	Operating Costs	$ (91,173)	$ -	($3,470)
247	All	WSCC Security Coordination		($1,255,891)							To assess	Direct Assignment	$ (1,255,891)	$ -	$0
248		**Total Other Revenue**		**($2,628,291)**									$ (2,298,610)	$ -	$ (39,689)
249		**Total Other Revenue %**										**Allocation %**	87.5%	0.0%	1.5%
250		**Net Operating Costs**													
251		**Total Salaries**	**$ 77,558,029**												

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252		**Total Salaries %**													
253		**Net Operating Costs**		**$169,110,838**									$128,192,592	$0	$4,920,897
254		**Net Operating Costs %**										**Allocation %**	75.8%	0.0%	2.9%
255		**1998 Bonds**													
256		**Infrastructure - Direct Assigned Items**													
257		EMS		$16,470,000		100.0%	0.0%	0.0%	0.0%	0.0%	To assess	Direct Assignment	$16,470,000	$0	$0
258		SI		$27,102,000		10.0%	0.0%	75.0%	10.0%	5.0%	To assess	Direct Assignment	$2,710,200	$0	$20,326,500
259		SA		$31,681,000		55.0%	0.0%	20.0%	15.0%	10.0%	To assess	Direct Assignment	$17,424,550	$0	$6,336,200
260		BBS (Billing & Settlements)		$48,173,000		25.0%	0.0%	25.0%	25.0%	25.0%	To assess	Direct Assignment	$12,043,250	$0	$12,043,250
261		MDAS (Metering)		$8,166,000		50.0%	0.0%	20.0%	20.0%	10.0%	To assess	Direct Assignment	$4,083,000	$0	$1,633,200
262		RMR-Software		$56,000		100.0%	0.0%	0.0%	0.0%	0.0%	To assess	Direct Assignment	$56,000	$0	$0
263		Market Anaysis Software		$238,000		0.0%	0.0%	0.0%	80.0%	20.0%	To assess	Direct Assignment	$0	$0	$0
264		Vehicles MDAS/Metering		$96,000		50.0%	0.0%	30.0%	15.0%	5.0%	To assess	Direct Assignment	$48,000	$0	$28,800
265		FERC Study Software		$11,000		0.0%	0.0%	0.0%	80.0%	20.0%	To assess	Direct Assignment	$0	$0	$0
266		GCP/RIG (Generator Communication with IS		$975,000		100.0%	0.0%	0.0%	0.0%	0.0%	To assess	Direct Assignment	$975,000	$0	$0
267		SRS Software (FTR related)		$1,049,000		70.0%	0.0%	15.0%	10.0%	5.0%	To assess	Direct Assignment	$734,300	$0	$157,350
268		ETC Software		$891,000		60.0%	0.0%	20.0%	15.0%	5.0%	To assess	Direct Assignment	$534,600	$0	$178,200
269		FTR Auction software		$17,000		70.0%	0.0%	15.0%	10.0%	5.0%	To assess	Direct Assignment	$11,900	$0	$2,550
270		ACC Upgrades (Communication btw ISO and		$1,162,000		100.0%	0.0%	0.0%	0.0%	0.0%	To assess	Direct Assignment	$1,162,000	$0	$0
271		**Total Infrastructure Direct Assigned Items**		**$136,087,000**									$56,252,800	$0	$40,706,050
272		**Infrastructure - Allocated Items**													
273		Issue Management System -Remedy		$692,000		75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	Operating Costs	$524,563	$0	$20,136
274		Security System - CUDA		$6,993,000		75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	Operating Costs	$5,300,966	$0	$203,487
275		Corporate Accounting - Oracle		$2,993,000		75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	Operating Costs	$2,268,810	$0	$87,092
276		Document Management System - EDMS		$1,715,000		75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	Operating Costs	$1,300,037	$0	$49,904
277		HR System - Imperativ		$136,000		75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	Operating Costs	$103,093	$0	$3,957
278		HR System - ABRA		$38,000		75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	Operating Costs	$28,805	$0	$1,106
279		System Management and Monitoring - Tivoli		$200,000		75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	Operating Costs	$151,608	$0	$5,820
280		Data Warehouse		$1,279,000		75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	Operating Costs	$969,532	$0	$37,217
281		Network Software		$630,000		75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	Operating Costs	$477,564	$0	$18,332
282		Facilities		$10,566,000		75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	Operating Costs	$8,009,439	$0	$307,456
283		Furniture		$5,391,000		75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	Operating Costs	$4,086,588	$0	$156,871
284		Facilities-Office Equipment		$1,330,000		75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	Operating Costs	$1,008,192	$0	$38,701
285		Transmission Display Software - TIDS		$139,000		75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	Operating Costs	$105,367	$0	$4,045
286		Other software and Enhancements		$3,482,000		75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	Operating Costs	$2,639,491	$0	$101,322
287		MCI Contract		$27,040,000		90.0%	0.0%	0.0%	7.0%	3.0%	Calculation	Telecom Dept (Outsourced Contracts:1441)	$24,336,000	$0	$0
288		IBM Contract		$6,816,000		76.1%	0.0%	2.8%	14.7%	6.4%	Calculation	IT Dept (1432)	$5,184,624	$0	$190,065
289		**Total Infrastructure Allocated Items**		**$69,440,000**									$56,494,679	$0	$1,225,512
290		**Subtotal Infrastructure**		**$205,527,000**									$112,747,479	$0	$41,931,562
291		**Subtotal Infrastructure %**										**Allocation %**	54.9%	0.0%	20.4%

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CALIFORNIA ISO
COST ALLOCATION MATRIX - 2003 BUDGET

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DRAFT: SUBJECT

Line #	ISO Dept #	OPERATING COSTS	Amount Labor	Amount Total Costs	FTE from Budget	Allocation: Control Area Services	Allocation: Dynamic Dispatch Export Service	Allocation: Scheduling Service	Allocation: Market Operations Service	Allocation: Real Time Market Operations Service	Check	Allocation/ Assignment Method	Total Costs Assigned/A: Control Area Services	Total Costs Assigned/A: Dynamic Dispatch Export Service	Total Costs Assigned/A: Scheduling Service
292		**Startup - Allocated Items**													
293		Trustee Costs		$5,692,000		54.9%	0.0%	20.4%	14.5%	10.3%	Calculation	Infrastructure subtotal	$3,122,503	$0	$1,161,280
294		Interest-Capitalized		$1,261,000		54.9%	0.0%	20.4%	14.5%	10.3%	Calculation	Infrastructure subtotal	$691,756	$0	$257,269
295		User Groups		$957,000		54.9%	0.0%	20.4%	14.5%	10.3%	Calculation	Infrastructure subtotal	$524,989	$0	$195,247
296		Startup Costs-through 3/31/98		$52,897,000		75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	Operating Costs	$40,097,983	$0	$1,539,231
297		Working Capital-3 months		$21,692,000		75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	Operating Costs	$16,443,380	$0	$631,208
298		**Total Startup Allocated Items**		**$82,499,000**									$60,880,610	$0	$3,784,235
299		**Other Software and Enhancements**													
300		2000 Spending: EMS/MDAS/Participating Lo		$1,651,155							To assess	Direct Assignment	$1,552,086	$0	$33,023
301		2000 Spending: SA/SI/BBS		$4,569,322							To assess	Direct Assignment	$685,398	$0	$3,015,753
302		2000 Spending: Other Systems/Vehicles		$1,240,714							To assess	Direct Assignment	$620,357	$0	$372,214
303		2001 Spending: Other Systems		$4,439,568		75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	Operating Costs	$3,365,365	$0	$129,185
304		2000 Spending: Facilities/Furniture/Office Eq		$1,473,241		75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	Operating Costs	$1,116,774	$0	$42,869
305		**Total Other Software and Enhancements**		**$13,374,000**									$7,339,980	$0	$3,593,045
306		**Total 1998 Bonds**											$180,968,070	$0	$49,308,841
307		**Total 1998 Bonds**		**$301,400,000**								**Allocation %**	60.0%	0.0%	16.4%
308		**Total 1998 Bonds %**													
309		**Total 2000 Bonds**													
310		Land & Building Costs		$9,300,000		75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	Operating Costs	$7,049,762	$0	$270,617
311		2000 Spending:SA/SI/BBS		$15,233,506							To assess	Direct Assignment	$8,530,763	$0	$2,132,691
312		2000 Spending: EMS/CIM/FDA		$1,435,154							To assess	Direct Assignment	$1,435,154	$0	$0
313		2000 Spending: Other Systems		$4,000,555		75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	Operating Costs	$3,032,576	$0	$116,411
314		2001 Spending: EMS		$5,286,679							To assess	Direct Assignment	$5,286,679	$0	$0
315		2001 Spending: SA/SI/BBS		$844,106							To assess	Direct Assignment	$320,760	$0	$101,293
316		**Total 2000 Bonds**		**$36,100,000**									$25,655,695	$0	$2,621,012
317		**Total 2000 Bonds %**										**Allocation %**	71.1%	0.0%	7.3%
318		**Total 1998 and 2000 Bonds**													
319		**Total 1998 and 2000 Bonds**		**$337,500,000**									$206,623,764	$0	$51,929,853
320		**Total 1998 and 2000 Bonds %**										**Allocation %**	61.2%	0.0%	15.4%
321		**Total Debt Service**													
322		Debt Service - Existing Debt (1998 and 2000 Bonds): Inc		$54,746,238		61.2%	0.0%	15.4%	14.8%	8.6%	Calculation	1998 & 2000 bonds	$33,516,663	$0	$8,423,597
323															
324		**Total Debt Service Cost**		**$54,746,238**									**$33,516,663**	**$0**	**$8,423,597**
325		**Total Debt Service Cost %**										**Allocation %**	61.2%	0.0%	15.4%
326		**Cash Funded Cap Ex: 2003 Capital Budget**													
327		2003 Budget: Operating Systems		$3,193,000							To assess	Direct Assignment	$2,554,400	$0	$223,510
328		2003 Budget: Furniture/Facilities/Office Equi		$445,000		75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	Operating Costs	$337,327	$0	$12,949
329		2003 Budget: Corporate Systems		$3,320,000		75.8%	0.0%	2.9%	14.8%	6.4%	Calculation	Operating Costs	$2,516,689	$0	$96,608
330		2003 Budget: MD02		$15,042,000							To assess	Direct Assignment	$6,016,800	$0	$3,158,820
331		**Total Cash Funded Cap Ex**		**$22,000,000**									**$11,425,216**	**$0**	**$3,491,886**
332		**Total Cash Funded Cap Ex%**										**Allocation %**	51.9%	0.0%	15.9%
333		**Total Cost of Service - 2003**											67.8%	48.1%	
334		**Gross O&M Costs**	**$ 77,558,029**	$171,739,129		75.8%	0.0%	2.9%	14.8%	6.4%			$130,491,202	$0	$4,960,586
335		**Other Costs and Income**		($2,628,291)		87.5%	0.0%	1.5%	7.7%	3.3%			$ (2,298,610)	$ -	$ (39,689)
336		**Net O&M Costs**		$169,110,838		76.0%	0.0%	2.9%	14.7%	6.4%			$128,192,592	$0	$4,920,897
337		**Debt Service**		$54,746,238		61.2%	0.0%	15.4%	14.8%	8.6%			$33,516,663	$0	$8,423,597

CALIFORNIA ISO
COST ALLOCATION MATRIX - 2003 BUDGET

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DRAFT: SUBJECT

Line #	ISO Dept #	OPERATING COSTS	Amount Labor	Amount Total Costs	FTE from Budget
338		Cash Funded Cap Ex		$22,000,000	
339		Total Cost of Service: Prior to Op. Reserve		$245,857,076	
340		Total Cost of Service %			
341		(Revenue Credit)/Shortfall		$ (8,256,705)	
342		Total Cost of Service		$237,600,371	
343		Total Cost of Service %			595.5

Allocation					Check	Allocation/ Assignment Method	Total Costs Assigned/A		
Control Area Services	Dynamic Dispatch Export Service	Scheduling Service	Market Operations Service	Real Time Market Operations Service			Control Area Services	Dynamic Dispatch Export Service	Scheduling Service
51.9%	0.0%	15.9%	23.8%	8.4%			$11,425,216	$0	$3,491,886
							$173,134,471	$0	$16,836,381
						Allocation % results before Revenue Credit or Deficiency	70.4%	0.0%	6.8%
70.4%	0.0%	6.8%	15.6%	7.1%		Allocated Pro-rata	$ (5,814,436)	$ -	$ (565,422)
							$167,320,035	$0	$16,270,959
						Net Allocation %	70.4%	0.0%	6.8%

DISCLAIMER

The data is intended for the designated recipients only and is provided solely for the purpose of fu
'2004 Rate Structure Project'. The data, in the form attached, is provided in response to Stakehol
indicate the ISO's concurrence in, or support for, its usefulness in developing a rate methodology.
ISO's position on any subject in the Project from either the inclusion or exclusion of any specific

completeness or accuracy of the data. The ISO is not necessarily the originator of the data.

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COST ALLOCATION MATRIX - 2003 BUDGET

TO CHANGE

Line #	ISO Dept #	OPERATING COSTS	Amount Labor	Amount Total Costs	Allocated	
					Market Operations Service	Real Time Market Operations Service
1	1500	Operations - Direct Costs				
2	1521	Grid Planning	$ 2,041,338			
3				$ 2,425,338	$ -	$ -
4	1542	Outage Coordination	$ 1,580,356			
5		Total Costs		$ 1,780,930	$0	$0
6	1543	Loads and Resources	$ 943,936			
7		Total Costs		$ 1,006,436	$ -	$ -
8	1544	Real-Time Scheduling	$ 2,578,768			
9		Total Costs		$ 2,680,968	$134,048	$134,048
10	1545	Grid Operations - Generat	$ 6,844,825			
11		Total Costs		$ 7,167,325	$358,366	$1,075,099
12	1546	Security Coordination	$ 1,207,891			
13		Total Costs		$ 1,255,891	$0	$0
14	1554	Special Projects Engineer	$ 601,931			
15		Total Costs		$ 860,981	$86,098	$0
16	1555	Operations Support Grou	$ 974,683			
17		Total Costs		$ 1,025,163	$0	$0
18	1558	Transmission Maintenanc	$ 1,141,103			
19		Total Costs		$ 1,804,953	$0	$0
20	1561	Operations Engineering S	$ 1,034,681			
21		Total Costs		$ 1,240,187	$0	$0
22	1562	Operations Engineering N	$ 1,168,863			
23		Total Costs		$ 1,226,703	$0	$0
24	1563	Coordinated Operations	$ 584,551			
25		Total Costs		$ 677,951	$135,590	$0
26	1565	Pre-Scheduling and Supp	$ 1,660,765			
27		Total Costs		$ 1,697,365	$84,868	$0
28	1566	Regional Coordination - G	$ 423,012			
29		Total Costs		$ 554,912	$0	$0

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COST ALLOCATION MATRIX - 2003 BUDGET
TO CHANGE

Line #	ISO Dept #	OPERATING COSTS	Amount Labor	Amount Total Costs	Allocated: Market Operations Service	Allocated: Real Time Market Operations Service
30	~~1549~~	~~Operations Training~~	~~$ 1,919,268~~			
31		Total Costs		$ 3,064,253	$459,638	$153,213
32	1559	Operations Application Sup	$ 447,958			
33				$ 458,472	$45,847	$0
34	**Total Operations Direct Salary Cost (**		**$ 25,153,929**			
35	**Total Operations Direct Salary %**					
36	**Total Operations Direct Costs**			**$ 28,927,828**	$ 1,304,456	$ 1,362,360
37	**Total Operations Direct Costs %**				4.5%	4.7%
38	**1500**	**Operations - Indirect Costs**				
39	1511	VP Grid Operations - Gen	$ 365,202			
40		Total		$ 1,011,957	$ 48,320	$ 49,339
41	1547	Engineering and Maintena	$ 289,222			
42		Total Costs		$ 1,154,222	$ -	$ -
43	1548	OSAT	$ 182,432			
44		Total Costs		$ 267,932	$ 32,868	$ 7,855
45	1564	Operations Scheduling - (	$ 281,362			
46		Total Costs		$ 322,862	$11,475	$7,027
47	**Total Operations Indirect Salaries**		**$ 1,118,218**			
48	**Total Operations Indirect Costs**			**$ 2,756,973**	$ 92,664	$ 64,221
49	**Total Operations Salaries**		**$ 26,272,147**			
50	**Total Operations Costs**			**$ 31,684,801**	$ 1,397,120	$ 1,426,581
51	**Operations Indirect Costs as % of Total**			9%		
52	**1700**	**VP Market Services**				
53	1722	Application Support	$ 414,256			
54		Total Costs		$ 510,466	$ 127,617	$ 127,617
55	1723	Tariff and Contract Implen	$ 667,205			
56		Total Costs		$ 896,883	$ -	$ -

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COST ALLOCATION MATRIX - 2003 BUDGET

TO CHANGE

Line #	ISO Dept #	OPERATING COSTS	Amount Labor	Amount Total Costs	Allocated: Market Operations Service	Allocated: Real Time Market Operations Service
57						
58	1724	BBS - PSS	$ 942,333			
59		Total Costs		$ 1,148,361	$ 287,090	$ 287,090
60	1725	BBS - FSS	$ 1,037,777			
61		Total Costs		$ 1,280,321	$ 320,080	$ 320,080
62	1731	Contracts and Special Prc	$ 1,153,955			
63		Total Costs		$ 1,439,963	$ -	$ -
64	1741	Client Relations	$ 2,054,540			
65		Total Costs		$ 2,299,956	$ 574,989	$ 574,989
66	1752	Manager of Markets	$ 2,156,353			
67		Total Costs		$ 2,355,353	$ 1,177,677	$ 471,071
68	1753	Market Engineering	$ 1,680,883			
69		Total Costs		$ 2,061,799	$ 1,649,439	$ 412,360
70	1755	Business Solutions	$ 739,166			
71		Total Costs		$ 942,745	$ 754,196	$ 188,549
72	1756	Market Quality - General	$ 1,940,408			
73		Total Costs		$ 2,102,565	$ 1,682,052	$ 420,513
74	1757	Market Integration	$ 587,361			
75				$ 835,895	$ 668,716	$ 167,179
76	**Total Market Services Direct Salaries**		**$13,374,237**			
77	**Total Market Services Direct Salaries %**					
78	**Total Market Services Direct Costs**			**$15,874,307**	7,241,856	2,969,447
79	**Total Market Services Direct Costs %**				45.6%	18.7%

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COST ALLOCATION MATRIX - 2003 BUDGET
TO CHANGE

Line #	ISO Dept #	OPERATING COSTS	Amount Labor	Amount Total Costs	Allocated: Market Operations Service	Allocated: Real Time Market Operations Service
80	1700	Market Services - Indirect Costs				
81	1711	VP Market Services - Gen	$ 394,287			
82		Total		$ 248,117	113,191	46,413
83	1721	Billing and Settlements-G	$ 347,911			
84		Total Costs		$ 353,911	$ 67,791	$ 67,791
85	1751	Market Operations - Gene	$ 331,747			
86		Total Costs		$ 959,968	$ 658,494	$ 191,994
87	**Total Market Services Indirect Salarie**		**$ 1,073,945**			
88	**Total Market Services Indirect Costs**			**$ 1,561,996**	839,476	306,198
89	**Total Market Services Salaries**		**14,448,182**			
90	**Total Market Services Costs**			**$17,436,303**	8,081,332	3,275,645
91	**Market Services Indirect as % of Total**			9%	46.35%	18.79%
92	1400	Information Services - Direct Costs				
93	1424	Asset Management	$ 845,319			
94		Total Costs		$ 21,742,188	$1,304,531	$434,844
95	1441	Outsourced Contracts	$ 159,466			
96		Total Costs		$ 29,683,478	$2,077,843	$890,504
97	1461	Control Systems	$ 2,186,977			
98		Total Costs		$ 2,321,654	$0	$0
99	1462	Field Data Acquisition Sys	$ 1,805,783			
100		Total Costs		$ 2,508,556	$0	$0
101	1467	Settlement Systems Servi	$ 980,615			
102		Total Costs		$ 1,064,350	$266,088	$266,088
103	**Total IS Direct Salaries**		**$ 5,978,160**		$ -	$ -
104	**Total IS Direct Salaries %**				0.0%	0.0%
105	**Total IS Direct Costs**			**$ 57,320,226**	$ 3,648,462	$ 1,591,436
106	**Total IS Direct Cost %**				6.37%	2.78%
107	1600	Legal - Direct Costs				
108	1641	Market Analysis	$ 1,997,346			
109		Total		$ 3,053,880	$ 2,443,104	$ 610,776
110	1642	Market Surveillance Comr	$ -		$ -	$ -
111		Total		$ 640,750	$ 512,600	$ 128,150
112	1661	Compliance - General	$ 1,150,095			

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COST ALLOCATION MATRIX - 2003 BUDGET
TO CHANGE

Line #	ISO Dept #	OPERATING COSTS	Amount Labor	Amount Total Costs	Allocated	
					Market Operations Service	Real Time Market Operations Service
113				$ 1,456,895	$ 218,534	$ 72,845
114	1662	Compliance - Audits	$ 357,191			
115		Total Costs		$ 416,191	$ 208,096	$ 70,752
116	**Total Legal Direct Salaries**		**$ 3,504,632**			
117	**Total Legal Direct Salaries %**					
118	**Total Legal Direct Costs**			**$ 5,567,716**	$ 3,382,334	$ 882,523
119	**Total Legal Direct Cost %**				60.7%	15.9%
120	**Subtotal Salaries Operations, Market Services, Indirec**			**$ 50,203,121**		
121	**Salary Percentages**					
122	**Subtotal Costs Operations, Market Services, Indirect I**			**$ 112,009,046**	$ 16,509,248	$ 7,176,185
123	**Expense Percentages**				14.7%	6.4%
124	1400	VP Information Services Indirect Costs				
125	1411	Chief Information Officer-	$ 391,143			
126		Total		$ 212,246	$13,510	$5,893
127	1422	Corporate & Enterprise Ap	$ 233,320			
128		Total Costs		$ 248,320	$ 36,600	$ 15,909
129	1466	Enterprise Applications	$ 764,123			
130		Total Costs		$ 816,499	$ 120,345	$ 52,311
131	1431	End User Support	$ 491,206			
132		Total Costs		$ 6,565,001	$967,629	$420,606
133	1432	Computer Operations - Ge	$ 403,068			
134		Total Costs		$ 430,975	$63,522	$27,612
135	1433	Network Operations	$ 1,549,597			
136		Total Costs		$ 1,629,905	$240,235	$104,425

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COST ALLOCATION MATRIX - 2003 BUDGET

TO CHANGE

Line #	ISO Dept #	OPERATING COSTS	Amount Labor	Amount Total Costs	Allocated: Market Operations Service	Allocated: Real Time Market Operations Service
137	1442	Production Support	$ 2,440,565			
138		Total Costs		$ 2,581,165	$380,443	$165,370
139	1451	Information Security	$ 1,038,281			
140		Total Costs		$ 1,509,500	$222,488	$96,711
141	1463	Operations Applications -	$ 292,237			
142		Total Costs		$ 323,539	$21,389	$15,861
143	1471	IT Planning	$ 628,349			
144		Total Costs		$ 770,116	$113,509	$49,340
145	1468	Corporate Application Sup	$ 1,188,702			
146				$ 1,333,287	$196,516	$85,421
147	1469	Analytical and Reporting	$ 984,106			
148				$ 1,055,106	$155,514	$67,598
149	1481	Markets and Scheduling	$ 1,267,761			
150		Total Costs		$ 1,520,628	$224,129	$97,423
151	**Total IS Indirect Salaries**		**$ 11,672,458**			
152	**Total IS Indirect Costs**			**$ 18,996,287**	$ 2,755,831	$ 1,204,479
153	**Total IS Operating Salaries**		**$ 17,650,618**			
154	**Total IS Operating Costs**			**$76,316,513**	$ 6,404,293	$ 2,795,915
155	**IS Indirect Costs as % of IT Operating Costs**			25%		
156	**Operating Costs and Salaries Before Corporate Indirects**					
157	**Total Operating Salaries**		**$ 61,875,579**			
158	**Total Operating Salaries %**					

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COST ALLOCATION MATRIX - 2003 BUDGET

TO CHANGE

Line #	ISO Dept #	OPERATING COSTS	Amount Labor	Amount Total Costs	Allocated: Market Operations Service	Allocated: Real Time Market Operations Service
159	**Total Operating Costs**			**$131,005,333**	**$19,265,079**	**$8,380,664**
160	**Total Operating Costs %**				14.7%	6.4%
161	**1300**	**Finance - Corporate Indirect Costs**				
162	1321	Accounting	$ 836,830			
163		Total		$ 2,168,530	$ 318,895	$ 138,725
164	1331	Financial Planning and Tr	$ 714,782			
165		Total		$ 2,511,009	$ 369,258	$ 160,634
166	1351	Facilities	$ 641,351			
167		Total		$ 5,812,962	$ 854,829	$ 371,866
168	1361	Office Administration	$ 643,601			
169		Total		$ 2,227,171	$ 327,518	$ 142,476
170	**Total Finance Indirect Costs**			**$12,719,672**	$ 1,870,500	$ 813,702
171	**Total Finance Op Salaries b/f CFO**		**$ 2,836,564**			
172	**Finance Indirect as % of Fin Operating Costs**			100%	14.7%	6.4%
173	**1300**	**Finance - Based on Finance Corporate Indirect Costs**				
174						
175	1311	CFO - General	$ 420,090			
176		Total		$ 424,204	$ 62,382	$ 27,137
177	**Total Finance Op Salaries**		**$ 3,256,654**		$ -	$ -
178	**Total Finance Operating Costs**			**$ 13,143,876**	$ 1,932,882	$ 840,839
179	**Finance Indirect as % of Fin Operating Costs**			100%		
180	**1600**	**Legal: Chief Counsel - Corporate Indirect Costs**				
181	1631	Legal and Regulatory	$ 3,330,071			
182		Total		$ 13,118,010	$1,929,078	$839,184
183	**Total Legal Indirect Salaries**		**$ 3,330,071**			
184	**Total Legal Indirect Costs**			**$ 13,118,010**	$ 1,929,078	$ 839,184
185	**Total Legal Salaries**		**$ 6,834,703**			
186	**Total Legal Costs**			**$18,685,726**	$5,311,412	$1,721,708
187	**Indirect as % of Total**			70.2%	#DIV/0!	#DIV/0!
188	**1600**	**Legal: Chief Counsel - Based on Legal Corporate Indirect and**				

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COST ALLOCATION MATRIX - 2003 BUDGET
TO CHANGE

Line #	ISO Dept #	OPERATING COSTS	Amount Labor	Amount Total Costs	Allocated: Market Operations Service	Allocated: Real Time Market Operations Service
189	1611	VP General Counsel - Ge	$ 468,583			
190		Total		$ 385,985	$102,236	$34,002
190	**Total Legal Salaries**		**$ 7,303,286**			
191	**Total Legal Costs**			**$19,071,711**	$5,413,648	$1,755,710
191	**Indirect as % of Total**			72%	#DIV/0!	#DIV/0!
192	**1800**	**VP Corporate and Strategic Development - Corporate Indirect**				
193	1821	Communications	$ 452,711			
194		Total Costs		$ 865,811	$ 127,322	$ 55,388
195	1831	Strategic Development	$ 477,745			
196				$ 693,745	$ 102,019	$ 44,380
197	1851	Project Office	$ 583,258			
198				$ 657,758	$ 96,727	$ 42,078
199	1861	Regulatory Policy	$ 585,142			
200		Total Costs		$ 1,430,767	$ 210,402	$ 91,529
201	**Total Corporate and Strategic Devpt**		**$ 2,098,856**			
202	**Total Corporate and Strategic Devpt b/f HR**			**$3,648,081**	$ 536,471	$ 233,375
203					#DIV/0!	#DIV/0!
204	**1800**	**VP Corporate and Strategic Development - Based on Corporat**				
205	1811	VP Corporate and Strateg	$ 392,226			
206		Total Costs		$ 497,434	$ 73,150	$ 31,822
207	**Total Corporate and Strategic Devt b**		**$ 2,491,082**			
208	**Total Corporate and Strategic Devt b/f HR**			**$4,145,515**	$ 609,622	$ 265,197
209	**Cost Allocation Percentage**				14.7%	6.4%
210	**1241**	**MD02**				
211	1241	MD02	$ 882,609			
212		Total Costs		$ 909,609	$ 136,441	$ 45,480
213	MD02		**$ 882,609**			

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COST ALLOCATION MATRIX - 2003 BUDGET

TO CHANGE

Line #	ISO Dept #	OPERATING COSTS	Amount Labor	Amount Total Costs	Allocated: Market Operations Service	Allocated: Real Time Market Operations Service
214				$ 909,609	$ 136,441	$ 45,480
215	Cost Allocation Percentage				15.0%	5.0%
216						
217		Total Costs and Salaries before HR/CEO				
218		Total Costs and Salaries before HR/CEO				
219	Total Salaries before HR/CEO		$ 72,304,578			
220	Total Salaries before HR/CEO %					
221	Total Costs before HR/CEO			$ 162,708,328	$ 23,975,338	$ 10,405,367
222	Total Costs before HR/CEO %				14.7%	6.4%
223	1100/1200	CEO / Human Resources - Corporate Indirects				
224	1111	CEO - General	$ 744,874			
225		Total		$ 730,899	$ 107,483	$ 46,757
226	1841	Human Resources	$ 1,166,617			
227		Total		$ 4,794,842	$ 705,109	$ 306,735
228	1651	Board of Governors				
229		Total		$ 163,100	$ 23,985	$ 10,434
230	Total CEO/HR Salaries		$ 1,911,491			
231	Total CEO/HR Costs			$ 5,688,841	$ 836,576	$ 363,926
232	Total Salaries Prior to Salary Adjustn		$ 74,216,069			
233	Total Salaries Prior to Salary Adjustments %					
234	Total Costs Prior to Salary Adjustments			168,397,169	$ 24,811,914	$ 10,769,293
235	Total Costs Prior to Salary Adjustments &				14.7%	6.4%
236		Other Costs				
237	All	Salary Adjustments, next	$ 3,341,960	$3,341,960	492,410	213,724
238	Total Other Costs		$ 3,341,960	$3,341,960	$492,410	$213,724
239		Gross Operating Costs				
240	Total Operating Salaries		$ 77,558,029			
241	Total Operating Salaries %					
242	Gross Operating Costs			$171,739,129	$25,304,324	$10,983,017
243	Gross Operating Costs %				14.7%	6.4%
244		Other Revenues				
245	All	Interest Revenues		($1,252,400)	($184,543)	($80,092)
246	All	SC Application and Training Fees		($120,000)	($17,682)	($7,674)
247	All	WSCC Security Coordination		($1,255,891)	$0	$0
248	Total Other Revenue			($2,628,291)	$ (202,225)	$ (87,766)
249	Total Other Revenue %				7.7%	3.3%
250		Net Operating Costs				
251	Total Salaries		$ 77,558,029			

CALIFORNIA ISO

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COST ALLOCATION MATRIX - 2003 BUDGET

TO CHANGE

Line #	ISO Dept #	OPERATING COSTS	Amount Labor	Amount Total Costs	Allocated: Market Operations Service	Allocated: Real Time Market Operations Service
252	**Total Salaries %**					
253	**Net Operating Costs**			**$169,110,838**	$25,102,099	$10,895,251
254	**Net Operating Costs %**				14.8%	6.4%
255		1998 Bonds				
256		Infrastructure - Direct Assigned Items				
257		EMS		$16,470,000	$0	$0
258		SI		$27,102,000	$2,710,200	$1,355,100
259		SA		$31,681,000	$4,752,150	$3,168,100
260		BBS (Billing & Settlements)		$48,173,000	$12,043,250	$12,043,250
261		MDAS (Metering)		$8,166,000	$1,633,200	$816,600
262		RMR-Software		$56,000	$0	$0
263		Market Anaysis Software		$238,000	$190,400	$47,600
264		Vehicles MDAS/Metering		$96,000	$14,400	$4,800
265		FERC Study Software		$11,000	$8,800	$2,200
266		GCP/RIG (Generator Communication with IS		$975,000	$0	$0
267		SRS Software (FTR related)		$1,049,000	$104,900	$52,450
268		ETC Software		$891,000	$133,650	$44,550
269		FTR Auction software		$17,000	$1,700	$850
270		ACC Upgrades (Communication btw ISO and		$1,162,000	$0	$0
271		**Total Infrastructure Direct Assigned Items**		**$136,087,000**	$21,592,650	$17,535,500
272		Infrastructure - Allocated Items				
273		Issue Management System -Remedy		$692,000	$102,718	$44,583
274		Security System - CUDA		$6,993,000	$1,038,011	$450,536
275		Corporate Accounting - Oracle		$2,993,000	$444,268	$192,829
276		Document Management System - EDMS		$1,715,000	$254,567	$110,492
277		HR System - Imperativ		$136,000	$20,187	$8,762
278		HR System - ABRA		$38,000	$5,641	$2,448
279		System Management and Monitoring - Tivoli		$200,000	$29,687	$12,885
280		Data Warehouse		$1,279,000	$189,849	$82,402
281		Network Software		$630,000	$93,515	$40,589
282		Facilities		$10,566,000	$1,568,372	$680,732
283		Furniture		$5,391,000	$800,217	$347,324
284		Facilities-Office Equipment		$1,330,000	$197,420	$85,687
285		Transmission Display Software - TIDS		$139,000	$20,633	$8,955
286		Other software and Enhancements		$3,482,000	$516,853	$224,334
287		MCI Contract		$27,040,000	$1,892,800	$811,200
288		IBM Contract		$6,816,000	$1,004,625	$436,687
289		**Total Infrastructure Allocated Items**		**$69,440,000**	$8,179,363	$3,540,446
290		**Subtotal Infrastructure**		**$205,527,000**	$29,772,013	$21,075,946
291		**Subtotal Infrastructure %**			14.5%	10.3%

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COST ALLOCATION MATRIX - 2003 BUDGET

TO CHANGE

Line #	ISO Dept #	OPERATING COSTS	Amount Labor	Amount Total Costs	Allocated: Market Operations Service	Allocated: Real Time Market Operations Service	
292		**Startup - Allocated Items**					
293		Trustee Costs		$5,692,000	$824,526	$583,691	
294		Interest-Capitalized		$1,261,000	$182,665	$129,310	
295		User Groups		$957,000	$138,628	$98,136	
296		Startup Costs-through 3/31/98		$52,897,000	$7,851,807	$3,407,978	
297		Working Capital-3 months		$21,692,000	$3,219,869	$1,397,544	
298		**Total Startup Allocated Items**		**$82,499,000**	$12,217,495	$5,616,660	
299		**Other Software and Enhancements**					
300		2000 Spending: EMS/MDAS/Participating Lo		$1,651,155	$33,023	$33,023	
301		2000 Spending: SA/SI/BBS		$4,569,322	$548,319	$319,853	
302		2000 Spending: Other Systems/Vehicles		$1,240,714	$186,107	$62,036	
303		2001 Spending: Other Systems		$4,439,568	$658,991	$286,027	
304		2000 Spending: Facilities/Furniture/Office Eq		$1,473,241	$218,682	$94,916	
305		**Total Other Software and Enhancements**		**$13,374,000**	$1,645,121	$795,854	
306		**Total 1998 Bonds**					
307		**Total 1998 Bonds**		**$301,400,000**	$43,634,629	$27,488,460	
308		**Total 1998 Bonds %**			14.5%	9.1%	
309		**Total 2000 Bonds**					
310		Land & Building Costs		$9,300,000	$1,380,453	$599,168	
311		2000 Spending:SA/SI/BBS		$15,233,506	$3,808,377	$761,675	
312		2000 Spending: EMS/CIM/FDA		$1,435,154	$0	$0	
313		2000 Spending: Other Systems		$4,000,555	$593,825	$257,742	
314		2001 Spending: EMS		$5,286,679	$0	$0	
315		2001 Spending: SA/SI/BBS		$844,106	$422,053	$0	
316		**Total 2000 Bonds**		**$36,100,000**	$6,204,708	$1,618,586	
317		**Total 2000 Bonds %**			17.2%	4.5%	
318		**Total 1998 and 2000 Bonds**					
319		**Total 1998 and 2000 Bonds**		**$337,500,000**	$49,839,337	$29,107,046	
320		**Total 1998 and 2000 Bonds %**			14.8%	8.6%	
321		**Total Debt Service**					
322		Debt Service - Existing Debt (1998 and 2000 Bonds): Inc		$54,746,238	$8,084,492	$4,721,485	
323							
324		**Total Debt Service Cost**		**$54,746,238**	**$8,084,492**	**$4,721,485**	
325		**Total Debt Service Cost %**			14.8%	8.6%	
326		**Cash Funded Cap Ex 2003 Capital Budget**					
327		2003 Budget: Operating Systems		$3,193,000	$319,300	$95,790	
328		2003 Budget: Furniture/Facilities/Office Equi		$445,000	$66,054	$28,670	
329		2003 Budget: Corporate Systems		$3,320,000	$492,807	$213,897	
330		2003 Budget: MD02		$15,042,000	$4,362,180	$1,504,200	
331		**Total Cash Funded Cap Ex**		**$22,000,000**	**$5,240,341**	**$1,842,556**	
332		**Total Cash Funded Cap Ex%**			23.8%	8.4%	
333		**Total Cost of Service - 2003**					
334		**Gross O&M Costs**	**$ 77,558,029**	$171,739,129	$25,304,324	$10,983,017	$171,739,129
335		**Other Costs and Income**		($2,628,291)	$ (202,225)	$ (87,766)	$ (2,628,291)
336		**Net O&M Costs**		$169,110,838	$25,102,099	$10,895,251	$169,110,838
337		**Debt Service**		$54,746,238	$8,084,492	$4,721,485	$54,746,238

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COST ALLOCATION MATRIX - 2003 BUDGET

TO CHANGE

Line #	ISO Dept #	OPERATING COSTS	Amount Labor	Amount Total Costs	Allocated: Market Operations Service	Allocated: Real Time Market Operations Service	
338	Cash Funded Cap Ex			$22,000,000	$5,240,341	$1,842,556	$22,000,000
339	**Total Cost of Service: Prior to Op. Reserve**			**$245,857,076**	**$38,426,932**	**$17,459,292**	$245,857,076
340	**Total Cost of Service %**				15.6%	7.1%	100.0%
341	**(Revenue Credit)/Shortfall**			$ (8,256,705)	$ (1,290,505)	$ (586,342)	$ (8,256,705)
342	**Total Cost of Service**			**$237,600,371**	**$37,136,426**	**$16,872,951**	$237,600,371
343	**Total Cost of Service %**				15.6%	7.1%	100.0%

DISCLAIMER

The data is intended for the designated recipients only and is provided solely for the purpose of fu
'2004 Rate Structure Project'. The data, in the form attached, is provided in response to Stakehol
indicate the ISO's concurrence in, or support for, its usefulness in developing a rate methodology.
ISO's position on any subject in the Project from either the inclusion or exclusion of any specific

completeness or accuracy of the data. The ISO is not necessarily the originator of the data.

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CALIFORNIA ISO This data is subject always to the Disclaimer issued by the ISO at the time of Appendix C5

FOR MID PROPOSAL

COST ALLOCATION MATRIX - 2003 BUDGET

WORKSHEET FOR ALLOCATION OF COSTS OF CERTAIN SUPERVISORY DEPARTMENTS

OPERATING EXPENSES

Operating Expenses - Cost Center 1311 CFO General

	Total	CAS	CONG	ASREQMO
1321	$ 2,168,530	47% $ 1,027,277	8% $ 168,937	45% $ 972,316
1331	$ 2,511,009	60% $ 1,501,215	10% $ 254,804	30% $ 750,990
1351	$ 5,312,962	64% $ 3,398,575	11% $ 634,003	25% $ 1,480,384
1361	$ 2,227,171	64% $ 1,417,067	11% $ 242,911	25% $ 567,193
Total	$ 12,219,672	$ 7,844,134	$ 1,300,655	$ 3,774,887
		64%	11%	30%
1311	$ 424,204	60.31%	10.60%	29.41%
		$ 255,843	$ 44,793	$ 119,354

SALARIES

Cost Center 1311 Salaries

	Total	CAS	CONG	ASREQMO
1321	$ 836,830	47% $ 396,423	8% $ 65,192	45% $ 375,214
1331	$ 714,782	60% $ 427,335	10% $ 73,671	30% $ 213,776
1351	$ 641,351	64% $ 408,068	11% $ 69,950	25% $ 163,333
1361	$ 643,601	64% $ 409,500	11% $ 70,196	25% $ 163,906
Total	$ 2,836,564	$ 1,641,326	$ 278,008	$ 916,230
		58%	10%	32%
1311	$ 420,090	58.79%	10.26%	30.94%
		$ 246,968	$ 43,116	$ 129,988

OPERATING EXPENSES

Operating Expenses - Cost Center 1311 CFO General

	Total	Control Area Services	Dynamic Dispatch Export Service	Scheduling Service	Market Operations Service	Real Time Market Operations Service
1321	$ 2,168,530	76% $ 1,650,449	0% $ -	3% $ 60,462	15% $ 318,895	6% $ 138,725
1331	$ 2,511,009	76% $ 1,911,106	0% $ -	3% $ 70,010	15% $ 368,258	6% $ 160,634
1351	$ 5,312,962	76% $ 4,424,193	0% $ -	3% $ 162,073	15% $ 854,829	6% $ 371,866
1361	$ 2,227,171	76% $ 1,695,080	0% $ -	3% $ 62,097	15% $ 327,518	6% $ 142,476
Total	$ 12,219,672	$ 9,680,828	$ -	$ 354,642	$ 1,870,500	$ 813,702
		79%	0%	3%	15%	6%
1311	$ 424,204	75.11%	0.00%	2.79%	14.77%	6.40%
		$ 318,727	$ -	$ 11,713	$ 61,777	$ 26,874

OPERATING EXPENSES

Operating Expenses - Cost Center 1432 -Computer Operations - General

	Total	CAS	CONG	ASREQMO
1431	$ 6,565,001	63% $ 4,140,334	10% $ 682,660	27% $ 1,742,007
1442	$ 2,581,165	56% $ 1,450,351	9% $ 239,135	35% $ 891,679
1451	$ 1,509,500	63% $ 951,993	10% $ 156,985	27% $ 400,542
1481	$ 1,520,628	56% $ 854,034	9% $ 140,813	35% $ 525,781
Total	$ 12,176,294	$ 7,396,712	$ 1,219,573	$ 3,559,009
		61%	10%	29%
1432	$ 430,975	56.31%	10.91%	32.78%
		$ 244,851	$ 40,371	$ 117,848

SALARIES

Cost Center 1432 Salaries

	Total	CAS	CONG	ASREQMO
1431	$ 491,206	63% $ 309,788	10% $ 51,078	27% $ 130,340
1442	$ 2,440,565	56% $ 1,371,349	9% $ 226,109	35% $ 843,108
1451	$ 1,038,281	63% $ 654,810	10% $ 107,965	27% $ 275,505
1481	$ 1,267,761	56% $ 712,015	9% $ 117,397	35% $ 438,348
Total	$ 5,237,813	$ 3,047,962	$ 502,548	$ 1,687,302
		58%	10%	32%
1432	$ 403,068	58.19%	9.59%	32.21%
		$ 234,551	$ 38,673	$ 129,844

OPERATING EXPENSES

Operating Expenses - Cost Center 1432 -Computer Operations - General

	Total	Resolving Energy Imbalances	Managing Transmission Flows	Scheduling Generator Loads and Transmission Facilities	Scheduling Generator Loads and Transmission Facilities	Administering Markets
1431	$ 6,565,001	76% $ 4,993,700	0% $ -	3% $ 183,066	15% $ 967,629	6% $ 420,606
1442	$ 2,581,165	75% $ 1,963,376	0% $ -	3% $ 71,976	15% $ 380,443	6% $ 165,370
1451	$ 1,509,500	76% $ 1,148,209	0% $ -	3% $ 42,093	15% $ 222,488	6% $ 96,711
1481	$ 1,520,628	76% $ 1,239,795	0% $ -	3% $ 45,450	15% $ 240,235	6% $ 104,425
Total	$ 12,176,294	$ 9,345,079	$ -	$ 342,585	$ 1,810,796	$ 787,111
		76%	0%	3%	15%	6%
1432	$ 430,975	78%	0%	3%	15%	6%
		$ 306,595	$ -	$ 11,240	$ 59,408	$ 25,824

OPERATING EXPENSES

Operating Expenses - Cost Center 1422 Corporate and Enterprise Apps General

	Total	CAS	CONG	ASREQMO
1466	$ 816,499	62% $ 504,371	9% $ 76,413	29% $ 235,815
1468	$ 1,333,287	61% $ 807,950	10% $ 133,215	29% $ 392,122
1469	$ 1,055,106	63% $ 665,421	10% $ 109,715	27% $ 279,970
Total	$ 3,204,892	$ 1,977,742	$ 319,343	$ 907,907
		62%	10%	28%
1422	$ 248,320	58.73%	9.96%	31.31%
		$ 145,975	$ 23,248	$ 86,097

SALARIES

Cost Center 1422 Salaries

	Total	CAS	CONG	ASREQMO
1466	$ 764,123	62% $ 471,923	9% $ 71,511	29% $ 220,688
1468	$ 1,188,702	61% $ 720,334	10% $ 118,769	29% $ 349,599
1469	$ 884,106	63% $ 620,644	10% $ 102,332	27% $ 261,130
Total	$ 2,976,931	$ 1,812,901	$ 292,612	$ 871,418
		61%	10%	29%
1422	$ 233,320	61.73%	9.96%	28.31%
		$ 144,023	$ 23,246	$ 66,051

OPERATING EXPENSES

Operating Expenses - Cost Center 1422 Corporate and Enterprise Apps General

	Total	Resolving Energy Imbalances	Managing Transmission Flows	Scheduling Generator Loads and Transmission Facilities	Scheduling Generator Loads and Transmission Facilities	Administering Markets
1466	$ 816,499	76% $ 621,074	0% $ -	3% $ 22,758	15% $ 120,345	6% $ 52,311
1468	$ 1,333,287	75% $ 1,014,171	0% $ -	3% $ 37,178	15% $ 196,516	6% $ 85,421
1469	$ 1,055,106	76% $ 802,572	0% $ -	3% $ 29,422	15% $ 155,514	6% $ 67,598
Total	$ 3,204,892	$ 2,437,817	$ -	$ 89,358	$ 472,378	$ 205,331
		76%	0%	3%	15%	6%
1422	$ 248,320	72%	0%	3%	15%	6%
		$ 177,476	$ -	$ 6,506	$ 34,390	$ 14,948

OPERATING EXPENSES

Operating Expenses - Cost Center 1463 Operations Applications - General

	Total	CAS	CONG	ASREQMO
1461	$ 2,321,654	100% $ 2,321,654	0% $ -	0% $ -
1462	$ 2,508,556	30% $ 749,148	8% $ 205,422	62% $ 1,553,986
1467	$ 1,064,350	15% $ 159,653	7% $ 74,505	78% $ 830,193
Total	$ 5,894,560	$ 3,230,455	$ 279,927	$ 2,384,178
		55%	5%	40%
1463	$ 373,539	58.23%	1.87%	24.16%
		$ 217,528	$ 6,989	$ 70,420

SALARIES

Cost Center 1463 Salaries

	Total	CAS	CONG	ASREQMO
1461	$ 2,188,977	100% $ 2,188,977	0% $ -	0% $ -
1462	$ 1,805,783	29% $ 515,568	11% $ 204,656	60% $ 1,085,560
1467	$ 980,615	15% $ 147,092	7% $ 68,643	78% $ 764,880
Total	$ 4,975,375	$ 2,849,638	$ 273,301	$ 1,850,436
		57%	5%	37%
1463	$ 292,237	73.81%	1.84%	24.34%
		$ 215,714	$ 5,384	$ 71,140

OPERATING EXPENSES

Operating Expenses - Cost Center 1463 Operations Applications - General

	Total	Resolving Energy Imbalances	Managing Transmission Flows	Scheduling Generator Loads and Transmission Facilities	Scheduling Generator Loads and Transmission Facilities	Administering Markets
1461	$ 2,321,654	100% $ 2,321,654	0% $ -	0% $ -	0% $ -	0% $ -
1462	$ 2,508,556	100% $ 2,508,556	0% $ -	0% $ -	0% $ -	0% $ -
1467	$ 1,064,350	25% $ 266,088	0% $ -	25% $ 266,088	25% $ 266,088	25% $ 266,088
1481	$ 1,520,628	76% $ 1,150,673	0% $ -	3% $ 42,403	15% $ 224,129	6% $ 97,423
Total	$ 7,416,188	$ 6,247,971	$ -	$ 308,490	$ 490,216	$ 363,511
		84%	0%	4%	7%	5%
1463	$ 373,539	84%	0%	4%	7%	5%
		$ 246,433	$ -	$ 12,155	$ 19,320	$ 14,328

Cost Center 1547

	Total	CAS	CONG	ASREQMO
1543	$ 1,006,436	100% $ 1,006,436	0% $ -	0% $ -
1561	$ 1,240,187	100% $ 1,240,187	0% $ -	0% $ -

Cost Center 1547

	Total	CAS	CONG	ASREQMO
1543	$ 943,936	100% $ 943,936	0% $ -	0% $ -
1561	$ 1,024,681	100% $ 1,024,681	0% $ -	0% $ -

Cost Center 1547

	Total	Resolving Energy Imbalances	Managing Transmission Flows	Scheduling Generator Loads and Transmission Facilities	Scheduling Generator Loads and Transmission Facilities	Administering Markets
1543	$ 1,006,436	100% $ 1,006,436	0% $ -	0% $ -	0% $ -	0% $ -
1561	$ 1,240,187	100% $ 1,240,187	0% $ -	0% $ -	0% $ -	0% $ -

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FOR MID PROPOSAL

COST ALLOCATION MATRIX - 2003 BUDGET

WORKSHEET FOR ALLOCATION OF COSTS OF CERTAIN SUPERVISORY DEPARTMENTS

1562	$ 1,226,703	100% $ 1,226,703	0% $ -	0% $ -
1558	$ 1,804,953	98% $ 1,773,365	0% $ -	2% $ 31,588
Total	$ 5,278,279	$ 5,246,691 99%	$ - 0%	$ 31,588 1%
1547	$ 1,154,222	99.40%	0.00%	0.60%
		$ 1,147,315	$ -	$ 6,907

1562	$ 1,168,863	100% $ 1,168,863	0% $ -	0% $ -
1558	$ 1,141,103	97% $ 1,111,005	0% $ -	3% $ 30,098
Total	$ 4,299,363	$ 4,258,489 99%	$ - 0%	$ 30,098 1%
1547	$ 289,222	99.30%	0.00%	0.70%
		$ 287,192	$ -	$ 2,030

1562	$ 1,226,703	100% $ 1,226,703	0% $ -	0% $ -	0% $ -	0% $ -
1558	$ 1,804,953	100% $ 1,804,953	0% $ -	0% $ -	0% $ -	0% $ -
Total	$ 3,278,279	$ 3,278,279 100%	$ - 0%	$ - 0%	$ - 0%	$ - 0%
1547	$ 1,154,222	100.00%	0.00%	0.00%	0.00%	0.00%
		$ 1,154,222	$ -	$ -	$ -	$ -

Cost Center 1548		CAS	CONG	ASREOMO
1549	$ 3,064,253	62% $ 1,890,463	24% $ 737,849	14% $ 435,942
1555	$ 1,025,163	61% $ 620,880	21% $ 220,082	18% $ 184,201
1559	$ 458,472	79% $ 361,629	10% $ 48,126	11% $ 48,717
1563	$ 677,951	60% $ 406,771	10% $ 67,795	30% $ 203,385
Total	$ 5,225,839	$ 3,279,742 63%	$ 1,073,851 21%	$ 872,245 17%
1548	$ 287,932	76.53%	6.47%	17.00%
		$ 205,048	$ 17,342	$ 45,543

Cost Center 1548		CAS	CONG	ASREOMO
1549	$ 1,919,268	62% $ 1,191,898	25% $ 472,917	13% $ 254,453
1555	$ 974,683	61% $ 590,307	21% $ 209,245	18% $ 175,131
1559	$ 447,958	79% $ 353,336	10% $ 47,022	11% $ 47,600
1563	$ 584,551	60% $ 350,731	10% $ 58,455	30% $ 175,365
Total	$ 3,926,460	$ 2,486,272 63%	$ 787,639 20%	$ 652,549 17%
1548	$ 182,432	72.66%	9.01%	18.32%
		$ 132,563	$ 16,441	$ 33,429

Cost Center 1548		Resolving Energy Imbalances	Managing Transmission Flows	Scheduling Generator Loads and Transmission Facilities	Scheduling Generator Loads and Transmission Facilities	Administering Markets
1549	$ 3,064,253	65% $ 1,991,764	0% $ -	15% $ 459,638	15% $ 459,638	5% $ 153,213
1555	$ 1,025,163	100% $ 1,025,163	0% $ -	0% $ -	0% $ -	0% $ -
1559	$ 458,472	90% $ 412,625	0% $ -	0% $ -	10% $ 45,847	0% $ -
1563	$ 677,951	80% $ 542,361	0% $ -	0% $ -	20% $ 135,590	0% $ -
Total	$ 5,225,839	$ 3,971,913 76%	$ - 0%	$ 459,638 9%	$ 641,075 12%	$ 153,213 3%
1548	$ 287,932	71.01%	0.00%	8.20%	11.27%	2.53%
		$ 203,642	$ -	$ 23,566	$ 32,368	$ 7,855

Cost Center 1564		CAS	CONG	ASREOMO
1544	$ 2,680,968	75% $ 2,010,726	15% $ 402,145	10% $ 268,097
1542	$ 1,780,930	100% $ 1,780,930	0% $ -	0% $ -
1565	$ 1,697,365	74% $ 1,254,021	15% $ 248,406	11% $ 194,938
	$ 6,159,263	$ 5,045,679	$ 650,552	$ 463,034
Total	$ 6,159,263	$ 5,045,677 82%	$ 650,551 11%	$ 463,034 8%
1564	$ 322,862	81.92%	10.56%	7.52%
		$ 264,489	$ 34,101	$ 24,272

Cost Center 1564		CAS	CONG	ASREOMO
1544	$ 2,578,768	75% $ 1,934,076	15% $ 386,815	10% $ 257,877
1542	$ 1,580,356	100% $ 1,580,356	0% $ -	0% $ -
1565	$ 1,660,765	73% $ 1,217,556	15% $ 248,314	12% $ 194,895
Total	$ 5,819,889	$ 4,731,988 81%	$ 635,129 11%	$ 452,773 8%
1564	$ 281,362	81.31%	10.91%	7.78%
		$ 228,768	$ 30,705	$ 21,889

Cost Center 1564		Resolving Energy Imbalances	Managing Transmission Flows	Scheduling Generator Loads and Transmission Facilities	Scheduling Generator Loads and Transmission Facilities	Administering Markets
1544	$ 2,680,968	85% $ 2,278,823	0% $ -	5% $ 134,048	5% $ 134,048	5% $ 134,048
1542	$ 1,780,930	100% $ 1,780,930	0% $ -	0% $ -	0% $ -	0% $ -
1565	$ 1,697,365	90% $ 1,527,629	0% $ -	5% $ 84,868	5% $ 84,868	0% $ -
	$ 6,159,263	$ 5,587,383	$ -	$ 218,917	$ 218,917	$ 134,048
Total	$ 6,159,263	$ 5,587,381 91%	$ - 0%	$ 218,917 4%	$ 218,917 4%	$ 134,048 2%
1564	$ 322,862	90.72%	0.00%	3.55%	3.55%	2.18%
		$ 292,885	$ -	$ 11,475	$ 11,475	$ 7,027

Cost Center 1611 General Couns		CAS	CONG	ASREOMO
1631	$ 13,118,010	62% $ 8,097,100	10% $ 1,319,917	28% $ 3,700,993
1641	$ 3,053,880	23% $ 688,824	19% $ 589,477	58% $ 1,775,579
1651	$ 163,100	63% $ 102,480	11% $ 18,080	26% $ 42,540
1661	$ 1,456,895	82% $ 1,191,963	5% $ 80,118	13% $ 184,814
1662	$ 416,191	84% $ 348,359	5% $ 19,916	12% $ 47,916
Total	$ 18,208,076	$ 10,428,727 57%	$ 2,027,507 11%	$ 5,751,842 32%
1564	$ 322,862	57.28%	11.14%	31.59%
		$ 184,920	$ 35,951	$ 101,991

Cost Center 1611		CAS	CONG	ASREOMO
1631	$ 3,330,071	62% $ 2,055,488	10% $ 335,067	28% $ 939,515
1641	$ 1,997,346	25% $ 501,536	19% $ 373,952	56% $ 1,121,857
1651	$ -	0% $ -	0% $ -	0% $ -
1661	$ 1,150,095	83% $ 958,413	6% $ 63,894	11% $ 127,788
1662	$ 357,191	83% $ 297,659	6% $ 19,844	11% $ 39,688
Total	$ 6,834,703	$ 3,813,096 56%	$ 792,758 12%	$ 2,228,849 33%
1564	$ 281,362	55.79%	11.60%	32.61%
		$ 156,973	$ 32,635	$ 91,754

Cost Center 1611 General Counsel		Resolving Energy Imbalances	Managing Transmission Flows	Scheduling Generator Loads and Transmission Facilities	Scheduling Generator Loads and Transmission Facilities	Administering Markets
1631	$ 13,118,010	76% $ 9,984,000	0% $ -	3% $ 365,748	15% $ 1,929,078	6% $ 839,184
1641	$ 3,053,880	0% $ -	0% $ -	0% $ -	80% $ 2,443,104	20% $ 610,776
1651	$ 163,100	76% $ 124,134	0% $ -	3% $ 4,547	15% $ 23,985	6% $ 10,434
1661	$ 1,456,895	40% $ 582,758	0% $ -	40% $ 582,758	15% $ 218,534	5% $ 72,845
1662	$ 416,191	0% $ -	0% $ -	33% $ 137,343	50% $ 208,096	17% $ 70,752
Total	$ 18,208,076	$ 10,690,892 59%	$ - 0%	$ 1,090,396 6%	$ 4,822,796 26%	$ 1,603,991 9%
1564	$ 322,862	58.72%	0.00%	5.99%	26.49%	8.81%
		$ 189,569	$ -	$ 19,335	$ 85,517	$ 28,442

Cost Center 1721		CAS	CONG	ASREOMO
1722	$ 510,466	19% $ 96,796	7% $ 35,712	74% $ 377,957
1723	$ 896,883	90% $ 807,195	0% $ -	10% $ 89,688
1724	$ 1,148,361	17% $ 193,228	8% $ 88,510	75% $ 866,623
1725	$ 1,280,321	16% $ 200,292	7% $ 94,667	77% $ 985,362
Total	$ 3,836,031	$ 1,297,511 34%	$ 218,889 6%	$ 2,319,631 60%
1721	$ 353,911	33.82%	5.71%	60.47%
		$ 119,708	$ 20,195	$ 214,008

Cost Center 1721		CAS	CONG	ASREOMO
1722	$ 414,256	19% $ 78,709	7% $ 28,998	74% $ 306,549
1723	$ 667,205	90% $ 600,485	0% $ -	10% $ 66,721
1724	$ 942,333	17% $ 159,879	8% $ 73,833	75% $ 708,621
1725	$ 1,037,777	16% $ 161,664	7% $ 75,294	77% $ 800,819
Total	$ 3,061,571	$ 1,000,736 33%	$ 178,125 6%	$ 1,882,710 61%
1721	$ 347,911	32.69%	5.82%	61.49%
		$ 113,722	$ 20,242	$ 213,948

Cost Center 1721		Resolving Energy Imbalances	Managing Transmission Flows	Scheduling Generator Loads and Transmission Facilities	Scheduling Generator Loads and Transmission Facilities	Administering Markets
1722	$ 510,466	25% $ 127,617	0% $ -	25% $ 127,617	25% $ 127,617	25% $ 127,617
1723	$ 896,883	100% $ 896,883	0% $ -	0% $ -	0% $ -	0% $ -
1724	$ 1,148,361	25% $ 287,090	0% $ -	25% $ 287,090	25% $ 287,090	25% $ 287,090
1725	$ 1,280,321	25% $ 320,080	0% $ -	25% $ 320,080	25% $ 320,080	25% $ 320,080
Total	$ 3,836,031	$ 1,631,670 43%	$ - 0%	$ 734,787 19%	$ 734,787 19%	$ 734,787 19%
1721	$ 353,911	42.54%	0.00%	19.15%	19.15%	19.15%
		$ 150,537	$ -	$ 67,791	$ 67,791	$ 67,791

Cost Center 1751		CAS	CONG	ASREOMO
1752	$ 2,355,353	29% $ 677,679	30% $ 706,606	41% $ 971,068
1753	$ 2,061,799	32% $ 653,659	28% $ 578,688	40% $ 829,452
1755	$ 942,745	25% $ 237,599	10% $ 98,675	64% $ 606,471
1757	$ 835,895	25% $ 210,108	30% $ 250,769	45% $ 375,019
Total	$ 6,195,792	$ 1,779,046 29%	$ 1,634,737 26%	$ 2,782,010 45%
1751	$ 959,968	20.00%	30.00%	50.00%
		$ 191,994	$ 287,990	$ 479,984

Cost Center 1751		CAS	CONG	ASREOMO
1752	$ 2,156,353	29% $ 625,342	30% $ 646,906	41% $ 884,105
1753	$ 1,660,883	33% $ 550,812	28% $ 464,413	40% $ 665,658
1755	$ 739,166	26% $ 192,183	10% $ 73,917	64% $ 473,066
1757	$ 587,361	25% $ 146,840	30% $ 176,208	45% $ 264,312
Total	$ 5,143,763	$ 1,515,177 29%	$ 1,361,444 26%	$ 2,287,141 44%
1751	$ 331,747	20.00%	30.00%	50.00%
		$ 66,349	$ 99,524	$ 165,874

Cost Center 1751		Resolving Energy Imbalances	Managing Transmission Flows	Scheduling Generator Loads and Transmission Facilities	Scheduling Generator Loads and Transmission Facilities	Administering Markets
1752	$ 2,355,353	30% $ 706,606	0% $ -	0% $ -	50% $ 1,177,677	20% $ 471,071
1753	$ 2,061,799	0% $ -	0% $ -	0% $ -	80% $ 1,649,439	20% $ 412,360
1755	$ 942,745	0% $ -	0% $ -	0% $ -	80% $ 754,196	20% $ 188,549
1757	$ 835,895	0% $ -	0% $ -	0% $ -	80% $ 668,716	20% $ 167,179
Total	$ 6,195,792	$ 706,606 11%	$ - 0%	$ - 0%	$ 4,250,028 69%	$ 1,239,158 20%
1751	$ 959,968	11.40%	0.00%	0.00%	68.60%	20.00%
		$ 109,481	$ -	$ -	$ 658,494	$ 191,994

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FOR MID PROPOSAL

COST ALLOCATION MATRIX - 2003 BUDGET

WORKSHEET FOR ALLOCATION OF COSTS OF CERTAIN SUPERVISORY DEPARTMENTS

Cost Center 1811 VP Corporate s		CAB	CONG	ASREQMO
1821		64%	11%	25%
	$ 865,811	$ 550,884	$ 94,432	$ 220,495
1831		64%	11%	25%
	$ 693,745	$ 441,405	$ 75,665	$ 176,676
1841	1841 excluded due to circularity - depends on allocation of these cost centers			
1851		63%	10%	27%
	$ 657,758	$ 413,287	$ 67,917	$ 176,544
1861		63%	10%	27%
	$ 1,430,767	$ 899,011	$ 147,735	$ 384,022
Total	$ 3,648,081	$ 2,304,586	$ 385,748	$ 957,737
		63%	11%	26%
1811				
	$ 497,434	63.17%	10.57%	26.25%
		$ 314,243	$ 52,599	$ 130,592

Cost Center 1811		CAS	CONG	ASREQMO
1821		64%	11%	25%
	$ 452,711	$ 288,043	$ 49,376	$ 115,292
1831		64%	11%	25%
	$ 477,745	$ 303,972	$ 52,108	$ 121,667
1851		63%	10%	27%
	$ 583,258	$ 366,453	$ 60,225	$ 156,548
1861		63%	10%	27%
	$ 585,142	$ 367,669	$ 60,418	$ 157,054
Total	$ 2,098,856	$ 1,326,137	$ 222,126	$ 550,593
		63%	11%	26%
1811				
	$ 392,226	63.19%	10.58%	26.23%
		$ 247,829	$ 41,510	$ 102,887

Cost Center 1811 VP Corporate and		Resolving Energy Imbalances	Managing Transmission Flows	Scheduling Generator Loads and Transmission Facilities	Scheduling Generator Loads and Transmission Facilities	Administering Markets
1821		76%	0%	3%	15%	6%
	$ 865,811	$ 658,961	$ -	$ 24,140	$ 127,372	$ 55,388
1831		76%	0%	3%	15%	6%
	$ 693,745	$ 528,003	$ -	$ 19,343	$ 102,019	$ 44,380
1841		76%	0%	3%	15%	6%
	$ 4,794,842	$ 3,649,511	$ -	$ 133,687	$ 705,109	$ 306,735
1851		76%	0%	3%	15%	6%
	$ 657,758	$ 500,614	$ -	$ 18,338	$ 96,727	$ 42,078
1861		76%	0%	3%	15%	6%
	$ 1,430,767	$ 1,088,544	$ -	$ 39,882	$ 210,402	$ 91,529
Total	$ 8,442,923	$ 6,425,637	$ -	$ 235,390	$ 1,241,629	$ 540,110
		76%	0%	3%	15%	6%
1811						
	$ 497,434	76.11%	0.00%	2.79%	14.71%	6.40%
		$ 378,593	$ -	$ 13,869	$ 73,150	$ 31,822

DISCLAIMER

The data is intended for the designated recipients only and is provided solely for the purpose of furthering discussion and research in the ISO's '2004 Rate Structure Project'. The data, in the form attached, is provided in response to Stakeholders' requests and as such does not necessarily indicate the ISO's concurrence in, or support for, its usefulness in developing a rate methodology. No implications may be drawn regarding the ISO's position on any subject in the Project from either the inclusion or exclusion of any specific data. The ISO does not warrant the completeness or accuracy of the data. The ISO is not necessarily the originator of the data.

SCE GMC PROPOSAL RATES

Services:
CAS = Contol Area Services
DDES = Dynamic Dispatch Export Service
SS = Scheduling Service
MOS = Market Operations Service
RMOS = Real-Time Market Operations Service

GMC SERVICE COMPONENT	ALLOCATED COSTS	BILLING DETERMINANTS	RATE		Check: Revenue
CAS	$167,320,035	242,451,790	$0.6892	$/MWh	$167,092,606
DDES	--	3,300,000	$0.0689	$/MWh	$227,429
SS	$16,270,959	241,746,847	$0.0545	$/MWh	$13,184,723
MOS	$37,136,426	56,587,298	$0.7108	$/MWh	$40,222,662
RMOS	$16,872,951	16,786,796	$1.0051	$/MWh	$16,872,951
Total:	$237,600,371				$237,600,371

Notes on Rate Calculations:

1) DDES rate is set equal to 10% of CAS rate
This is accomplished by simultaneously calculating the CAS rate and DDES rates:
CAS rate = CAS costs / ((BDcas+ (0.1*BDddes)), and DDES rate = 0.1 * CAS rate
2) All costs allocated to SS are also collected from MOS
This is allomplished by simultaneously calculating the SS and MOS rates:
SSrate = SS costs/(BDss+BDmos), and
MOSrate = (SS costs + MOS costs - SS revenues)/BDmos

Billing Determinants:

Service	BD Volume	BD Description
CAS	242,451,790	MWh of Control Area Load (Exclusive of retail behind-the-meter)
DDES	3,300,000	MWHs of gen dynamically dispatched to other Control Areas over non-ISO T
SS	241,746,847	MWh of scheduled energy + self-provided AS (final schedules)
MOS	56,587,298	MWh of pur/sales of energy + AS
RMOS	16,786,796	MWh of uninstructed imbalance energy

Notes on Billing Determinants:

1) DDES volume is based on SCE's 5,400,000 annual MWh output from 56% share of Mohave, 34% owned by Nevada (14%) and SRP (20%)
2) All other BDs based on March 5, 2003 ISO "Aggregated Billing Determinant Data"
3) Control Area Load =

251,615,170	Control Area Gross Load (MWh)
-3,300,000	DDES Energy
-5,863,380	BTM load served by BTM gen (MWh)
242,451,790	

4) SS BD is:

237,746,847	Scheduled load (MWh)	
4,000,000	Self-provided AS (MWh)	**Preliminary estimate**
241,746,847		

5) MOS BD is based on ASREO volumes less uninstructed deviations

73,374,094	ASREO
-16,786,796	Uninstructed imbalance energy
56,587,298	

6) RMOS BD is equal to "sum of absolute net uninstructed deviations"

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ISO Dept #	Operating Costs	Dollars	Percent Assignment CAS	DDES	Sch Ser	Mkt Ser	RT Mkts	Check	Comments
1500	Operations - Direct Costs								All 1500 allocation based on Deane Lyon Conversation
1521	Grid Planning	2,425,338	100					×	All for reliable grid operations
1542	Outage Coordination	1,780,930	100					×	All for reliable grid operations.
1543	Loads and Resources	1,006,436	100					×	All for reliable grid operations.
1544	Real-Time Scheduling	2,680,968	85		5	5	5	×	Scheduling interties and external resources, mostly CAS but a little market
1545	Grid Operations - General	7,167,325	80			5	15	×	Mostly for eliable grid operations, includes some BEEP costs.
1546	Security Coordination	1,255,891	100					×	All for reliable grid operations.
1554	Special Projects Engineering	860,981	90			10		×	Research+Dev of special applications tools for ISO
1555	Operations Support Group	1,025,163	100					×	AS certification + RMR testing
1558	Transmission Maintenance	1,804,953	100					×	All for reliable grid operations.
1561	Operations Engineering South	1,240,187	100					×	All for reliable grid operations.
1562	Operations Engineering North	1,226,703	100					×	All for reliable grid operations.
1563	Coordinated Operations	677,951	80			20		×	Interface between operating floor and rest of ISO
1565	Pre-Scheduling and Support	1,697,365	90		5	5		×	Intertie scheduling, checks with other control areas
1566	Regional Coordination - General	554,912	100					×	WECC/NERC interaction
1549	Operations Training	3,064,253	65		15	15	5	×	Mostly training for operations but some market related
1559	Operations Application Support	458,472	90			10		×	WECC reliability criteria related mainly + plus others, mostly CAS
1511	VP Grid Operations - General	1,011,957	88		3		5		
1547	Engineering and Maintenance - General	1,154,222	98						
1548	OSAT	267,932	75		10		3		
1564	Operations Scheduling - General	322,862	91		4		2		
1700	VP Market Services								All 1700 based on conversations with Mike McGuffin
1722	Application Support	510,466	25		25	25	25	×	Settlements and Billing related
1723	Tariff and Contract Implementation	896,883	100					×	RMR Settlements related, all CAS
1724	BBS - PSS	1,148,361	25		25	25	25	×	Settlements related (Preliminary statements), more costs for real-time
1725	BBS - FSS	1,280,321	25		25	25	25	×	Settlements related (Final Statements), more costs for real-time
1731	Contracts and Special Projects	1,439,963	100					×	Administration of Contracts (RMR, PTO, MSS, etc). All CAS
1741	Client Relations	2,299,956	25		25	25	25	×	Client Relations is for all aspects of ISO Services, same as BBS
1752	Manager of Markets	2,355,353	30			50	20	×	Mostly market, but some CAS
1753	Market Engineering	2,061,799				80	20	×	All Market: 80% DA&HA, 20% RT
1755	Business Solutions	942,745				80	20	×	All Market
1756	Market Quality - General	2,102,565				80	20	×	All Market
1757	Market Integration	835,895				80	20	×	All Market
1400	Information Services - Direct Costs								
1424	Asset Management	21,742,188	92			6	2	×	Like ISO allocation, 8% market split between two categories
1441	Outsourced Contracts	29,683,478	90			7	3	×	Like ISO allocation, 8% market split between two categories
1461	Control Systems	2,321,654	100					×	All for reliable grid operations.
1462	Field Data Acquisition System (FDAS)	2,508,556	100					×	Enters data into EMS, all CAS
1467	Settlement Systems Services	1,064,350	25		25	25	25		Settlements and Billing related
1600	Legal - Direct Costs								
1641	Market Analysis	3,053,880				80	20	×	
1642	Market Surveillance Committee	640,750				80	20	×	
1661	Compliance - General	1,456,895	40		40	15	5	×	Like ISO allocation, 20% market split between two categories
1662	Compliance - Audits	416,191			33	50	17	×	Like ISO allocation, 67% market split between two categories
1241	MD02								
1241	MD02	909,609	60		20	15	5	×	Mostly for reliable Grid ops, but afects all aspects of ISO operations

	Other Revenues								
	WSCC Security Coordination	-1,255,891	100					×	All for reliable grid operations.
	Total Directs	110,100,768							
	1998 Bonds								
	Infrastructure - Direct Assigned Items								
	EMS	16,470,000	100					×	All for reliable grid operations.
	SI	27,102,000	10		75	10	5	×	Like ISO allocation, 5% to RT
	SA	31,681,000	55		20	15	10	×	Like ISO, 10% to RT
	BBS (Billing & Settlements)	48,173,000	25		25	25	25	×	Allocated like BBS above
	MDAS (Metering)	8,166,000	50		20	20	10	×	Metering supports both market and reliable control area operations
	RMR-Software	56,000	100					×	All for reliable grid operations.
	Market Anaysis Software	238,000				80	20	×	All for Market, 80/20 like others
	Vehicles MDAS/Metering	96,000	50		30	15	5	×	Metering supports both market and reliable control area operations
	FERC Study Software	11,000				80	20	×	All for Market, 80/20 like others
	GCP/RIG (Generator Communication with ISO)	975,000	100					×	All for reliable grid operations.
	SRS Software (FTR related)	1,049,000	70		15	10	5	×	Like ISO but move 60% cong to CAS
	ETC Software	891,000	60		20	15	5	×	Like ISO, but move cong and customer service to CAS
	FTR Auction software	17,000	70		15	10	5	×	Same as SRS software
	ACC Upgrades (Communication btw ISO and IOUs)	1,162,000	100					×	All for reliable grid operations.
	Other Software and Enhancements								
	2000 Spending: EMS/MDAS/Participating Load Prog	1,651,155	94		2	2	1	×	ISO Calculated row
	2000 Spending: SA/SI/BBS	4,569,322	15		66	12	7	×	ISO Calculated row
	2000 Spending: Other Systems/Vehicles	1,240,714	50		30	15	5	×	Same as Vehicles MDAS/Metering
	Total 2000 Bonds								
	2000 Spending:SA/SI/BBS	15,233,506	56		14	25	5	×	Like ISO Allocation
	2000 Spending: EMS/CIM/FDA	1,435,154	100					×	All CAS
	2001 Spending: EMS	5,286,679	100					×	All CAS
	2001 Spending: SA/SI/BBS	844,106	38		12	50		×	Like ISO Allocation
	Cash Funded Cap Ex: 2003 Capital Budget								
	2003 Budget: Operating Systems	3,193,000	80		7	10	3	×	Like ISO Allocation
	2003 Budget: MD02	15,042,000	40		21	29	10	×	Like ISO Allocation
	Shaded Yellow = SCE input								

RE Documents you requested 04-21-03.txt

From: Laurence Kirsch [ldkirsch@lrca.com]
Sent: Monday, April 21, 2003 10:02 PM
To: Arikawa, Ben
Subject: RE: Documents you requested

Thanks again for your help.

-----Original Message-----
From: Arikawa, Ben [mailto:BArikawa@caiso.com]
Sent: Monday, April 21, 2003 4:52 PM

To: Laurence Kirsch
Cc:
Subject: Documents you requested

Laurence,

Here are the documents that you requested during our phone call.

Note: The information attached is intended for the designated recipients only and is provided solely for the purpose of furthering discussion and research in the ISO's '2004 Rate Structure Project'. The information, in the form attached, is provided in response to Stakeholders' requests and as such does not necessarily indicate the ISO's concurrence in, or support for, its usefulness in developing a rate methodology. No implications may be drawn regarding the ISO's position on any subject in the Project from either the inclusion or exclusion of any specific data. The ISO does not warrant the completeness or accuracy of the data. The ISO is not necessarily the originator of the data.

Ben Arikawa
Senior Financial Analyst
California Independent System Operator
151 Blue Ravine Road
Folsom, CA 95630

Voice: (916) 608-5958
fax: (916) 351-2259

email: barikawa@caiso.com

From: CRCommunications
Sent: Monday, April 21, 2003 2:22 PM
To: ISO Market Participants
Subject: CAISO Notice: ISO 2004 GMC Rate Structure Project SC Data Release

Market Notice
April 21, 2003

ISO 2004 GMC Rate Structure Project
SC Data Release

Market Participants and Scheduling Coordinators:

Pursuant to an Initial Decision issued on May 10, 2002 in Docket No. ER01-313, FERC Administrative Law Judge Bobbie J. McCartney directed the California ISO to undertake a comprehensive review of its GMC rate structure during 2003. That project must permit effective stakeholder participation, including stakeholder testing of alternative methods of rate design. To facilitate that review, the ISO has been asked to release certain SC-related data to specified stakeholders. The SC specific data in question are non-coincident peak demand, load and exports, number of schedules, Net Interzonal Scheduled flows, purchases and sales of Ancillary Services (including self-provided amounts), Supplemental Energy and Imbalance Energy, billable quantities on a Final Settlement Statement, Scheduled load and exports, and net uninstructed deviations by 10 minute interval for September 2001 through August 2002.

To the extent that this request seeks information that is confidential and/or commercially sensitive under ISO Tariff Section 20.3.2., the ISO will require confidential treatment for such information. **Any stakeholder acquiring access to such data must first have executed the ISO's Confidentiality Agreement for this Project.** In addition the ISO has removed all means of identifying specific SCs. **Finally, the ISO does not currently intend to release any SC-related data for this Project until six months after the passage of the Trade Dates in question.**

The ISO plans to produce appropriate materials at the close of business April 25, 2003, unless the ISO receives by noon (PDT) on that date a FERC or other appropriate order that prohibits disclosure. If you have any questions, please contact ISO Senior Regulatory Counsel, Anthony Ivancovich, at aivancovich@caiso.com

Client Relations Communications11.20
CRCommunications@caiso.com

Re Example rate calculations 04-23-03.txt

From: JAN PRITCHARD [JanP@MID.ORG]
Sent: Wednesday, April 23, 2003 6:45 AM
To: BArikawa@caiso.com
Cc: lkirsch@lrca.com
Subject: Re: Example rate calculations

Ben,

MID is interested in presenting example rate calculations but would like to make that presentation in the same format as the ISO. It woul d
be very helpful if you would provide Laurence with as much information as possible regarding the ISO's presentation at your earliest convenience.

Thanks

Jan

2BBYvx.370000000.9914

>>> "Arikawa, Ben" <BArikawa@caiso.com> 04/22/03 03:37PM >>>
Since the ISO was asked to run through a sample rate calculation for the next GMC meeting, do you want to have the opportunity to do this also?

Note: the attached documents are circulated by the sender solely for the express purpose of informing discussion. Therefore, none of the contents may be regarded by the reader as any form of offer, undertaking, policy, proposal or commitment by the sender, author or the
California ISO.

Ben Arikawa
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email: barikawa@caiso.com

Updated billing determinants 04-23-03.txt

From: Arikawa, Ben
Sent: Wednesday, April 23, 2003 12:55 PM
To: Pritchard, Jan; Kirsch, Laurence
Cc: McGuffin, Mike; Leiber, Phil
Subject: Updated billing determinants

Jan and Laurence,

The attachment contains the aggregated billing determinants and is current as of April 23, 2003. This differs from the March 5th version

in that the maximum uninstructed deviation and uninstructed energy dat a
have been updated. We have addedhe MW-months of 12□CP ead to very Th

ISO's Market Usage charge. The individual components of that determinant are shown as you requested.

This does not contain all the billing determinant data used by all the

rate proposals. It should be updated in the next few days with all th e
data and will be posted to the public discussion site.

Note: the attached documents are circulated by the sender solely for the express purpose of informing discussion. Therefore, none of the contents may be regarded by the reader as any form of offer, undertaking, policy, proposal or commitment by the sender, author or the California ISO.

Ben Arikawa
Senior Financial Analyst
California Independent System Operator
151 Blue Ravine Road
Folsom, CA 95630

Voice: (916) 608-5958
fax: (916) 351-2259

email: barikawa@caiso.com

RE MID Numbers 04-24-03.txt

From: Leiber, Phil
Sent: Thursday, April 24, 2003 12:10 PM
To: 'lkirsch@svn.net'
Cc: Pritchard, Jan; Neal, Sean; rchemphill@lrca.com; Arikawa, Ben
Subject: RE: MID Numbers

We've now have a customer impact analysis for each of the three proposals.

We'll update the MID customer impact analysis by adding in the new SCHEDULING category.

We'll be releasing a consistent set of customer impact related analyses
for each of the three proposals.

Philip Leiber, Treasurer & Director of Financial Planning
California ISO
(916) 351-2168
(916) 351-2259 (fax)

-----Original Message-----
From: lkirsch@svn.net [mailto:lkirsch@svn.net]
Sent: Thursday, April 24, 2003 11:50 AM
To: Arikawa, Ben
Cc: Pritchard, Jan; Neal, Sean; rchemphill@lrca.com; Leiber, Phil
Subject: MID Numbers

Ben:

The attached spreadsheet presents the figures from the current draft of MID's rate design proposal. The ISO can use these for its bill impact estimates.

Within the next few hours, I will get you a write-up of MID's current proposal and of Monday's presentation.

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
****

RE MID Numbers 04-24-03a.txt

From: lkirsch@svn.net
Sent: Thursday, April 24, 2003 12:50 PM
To: Leiber, Phil
Cc: janp@mid.org; smn@dwgp.com; BArikawa@caiso.com; mmcguffin@caiso.com; rchemphill@lrca.com
Subject: RE: MID Numbers

Phil:

Thanks for the information. We'll adopt your 984 SC-month figure. As for the uninstructed deviation demand, the difference is not due to a data error but is instead due to our wanting a ratcheted (1 NCP) demand charge while the dataset has an unratcheted (12 NCP) demand charge. The explanation for how we derived our billing determinant is in a footnote, which I reproduce immediately below. Please let me know if you still think that there is a problem.

The change in the SC-month figure changes our numbers slightly. The revision is attached hereto.

Laurence

The footnote: The interval-by-interval dataset of uninstructed deviations show that, for the period September 2001 through June 2002: a) the maximum absolute deviation for each SC over the 10-month period, summed over SCs, is 4,523 MW; and b) the maximum absolute sum of the deviations of the SCs in any one interval is 584 MW. "Aggregated filling determinant data (revised 030423).xls," sheet "Max Uninstructed Dev demand," shows that the maximum absolute deviation for each SC in each month, summed over SCs, ranges between 1,668 MW and 2,549 MW. The substantial (and unsurprising) diversity of imbalances among SCs yields this effect of the billing determinants summing to substantially larger figures over larger periods of time. Because we are proposing the billing determinant be the highest value over the most recent 12-months, the 10-month figure is the one that is most relevant to our proposal. Over the course of a year, this figure is equivalent to 54,276 MW-months (equals 12 months times 4,523 MW).

On 24 Apr 2003, at 12:27, Leiber, Phil wrote:

We have some differences in billing determinants

RE MID Numbers 04-24-03a.txt

For Resolving Energy Imbalances

Uninstructed Deviation Demand

Per MID: 54,276
Per ISO: 25,238

This is due to an update in the query we ran previously.

Number of SCs:

For purposes of the comparative analysis, we're applying the charge to
Scheduling coordinator IDs rather than Scheduling coordinators (the ISO is doing the same in its proposal currently).

Difference:
Per MID: 876 SC months
Per ISO: 984 SC months

Attached is a summary that would show the rate effects of these.

****

Laurence D. Kirsch
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Please visit our website at WWW.LRCA.COM

****

RE MID Numbers 04-24-03b.txt

From: Leiber, Phil
Sent: Thursday, April 24, 2003 12:54 PM
To: McGuffin, Mike
Cc: Pritchard, Jan; Neal, Sean; Arikawa, Ben; rchemphill@lrca.com; 'lkirsch@svn.net'
Subject: RE: MID Numbers

Mike,

Can you generate figures for the "ratcheted (1 NCP) demand charge" per

SC based on MID's approach?

If so, please forward to me for inclusion in the customer impact analysis.

If not, please respond to Lawrence & others so we can decide what to d
o
instead.

Thanks...

Phil

-----Original Message-----
From: lkirsch@svn.net [mailto:lkirsch@svn.net]
Sent: Thursday, April 24, 2003 12:50 PM
To: Leiber, Phil
Cc: Pritchard, Jan; Neal, Sean; Arikawa, Ben; McGuffin, Mike; rchemphill@lrca.com
Subject: RE: MID Numbers

Phil:

Thanks for the information. We'll adopt your 984 SC-month figure. As for the uninstructed deviation demand, the difference is not due to a data error but is instead due to our wanting a ratcheted (1 NCP) demand charge while the dataset has an unratcheted (12 NCP) demand charge. The explanation for how we derived our billing determinant is in a footnote, which I reproduce immediately below. Please let me know if you still think that there is a problem.

The change in the SC-month figure changes our numbers slightly. The revision is attached hereto.

Laurence

RE MID Numbers 04-24-03b.txt

The footnote: The interval-by-interval dataset of uninstructed deviations show that, for the period September 2001 through June 2002: a) the maximum absolute deviation for each SC over the 10-month period, summed over SCs, is 4,523 MW; and b) the maximum absolute sum of the deviations of the SCs in any one interval is 584 MW. "Aggregated filling determinant data (revised 030423).xls," sheet "Max Uninstructed Dev demand," shows that the maximum absolute deviation for each SC in each month, summed over SCs, ranges between 1,668 MW and 2,549 MW. The substantial (and unsurprising) diversity of imbalances among SCs yields this effect of the billing determinants summing to substantially larger figures over larger periods of time. Because we are proposing the billing determinant be the highest value over the most recent 12-months, the 10-month figure is the one that is most relevant to our proposal. Over the course of a year, this figure is equivalent to 54,276 MW-months (equals 12 months times 4,523 MW).

On 24 Apr 2003, at 12:27, Leiber, Phil wrote:

We have some differences in billing determinants

For Resolving Energy Imbalances

Uninstructed Deviation Demand

Per MID: 54,276
Per ISO: 25,238

This is due to an update in the query we ran previously.

Number of SCs:

For purposes of the comparative analysis, we're applying the charge to
Scheduling coordinator IDs rather than Scheduling coordinators (the ISO is doing the same in its proposal currently).

Difference:
Per MID: 876 SC months
Per ISO: 984 SC months

RE MID Numbers 04-24-03b.txt

Attached is a summary that would show the rate effects of these.

****

Laurence D. Kirsch
Laurits R. Christensen Associates, Inc.
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voice: (415) 663-8608
fax: (415) 663-8818

Please visit our website at WWW.LRCA.COM

****

RE MID Numbers 04-24-03d.txt

From: McGuffin, Mike
Sent: Thursday, April 24, 2003 1:29 PM
To: 'lkirsch@svn.net'; Leiber, Phil
Cc: Arikawa, Ben; Pritchard, Jan; Neal, Sean; rchemphill@lrca.com
Subject: RE: MID Numbers

Generating any numbers on a rolling 12 month basis is nearly impossible, given the current settlement system. I could get the numbers, but if we choose to implement this method, it would be necessary to calculate the data in advance of the trade year and bill a
static amount on a monthly basis. I'll look into generating the numbers by SC for the customer impact...

Mike

-----Original Message-----
From: lkirsch@svn.net [mailto:lkirsch@svn.net]
Sent: Thursday, April 24, 2003 1:18 PM
To: Leiber, Phil
Cc: Arikawa, Ben; McGuffin, Mike; Pritchard, Jan; Neal, Sean; rchemphill@lrca.com
Subject: RE: MID Numbers

Phil:

If you can give us a better 1 NCP number for uninstructed deviation demand, that would helpful. The only other MID number that will be affected by that update will be the uninstructed deviation demand price.

Laurence

On 24 Apr 2003, at 12:54, Leiber, Phil wrote:

Mike,

Can you generate figures for the "ratcheted (1 NCP) demand charge" per SC based on MID's approach?

If so, please forward to me for inclusion in the customer impact analysis.

If not, please respond to Lawrence & others so we can decide what to
do instead.

Thanks...

Phil

-----Original Message-----
From: lkirsch@svn.net [mailto:lkirsch@svn.net]
Sent: Thursday, April 24, 2003 12:50 PM
To: Leiber, Phil
Cc: Pritchard, Jan; Neal, Sean; Arikawa, Ben; McGuffin, Mike; rchemphill@lrca.com
Subject: RE: MID Numbers

Phil:

Thanks for the information. We'll adopt your 984 SC-month figure. As
for the uninstructed deviation demand, the difference is not due to a data error but is instead due to our wanting a ratcheted (1 NCP) demand charge while the dataset has an unratcheted (12 NCP) demand charge. The explanation for how we derived our billing determinant is in a footnote, which I reproduce immediately below. Please let me know if you still think that there is a problem.

The change in the SC-month figure changes our numbers slightly. The revision is attached hereto.

Laurence

The footnote: The interval-by-interval dataset of uninstructed deviations show that, for the period September 2001 through June 2002: a) the maximum absolute deviation for each SC over the 10-month period, summed over SCs, is 4,523 MW; and b) the maximum absolute sum of the deviations of the SCs in any one interval is 584 MW. "Aggregated filling determinant data (revised 030423).xls," sheet "Max Uninstructed Dev demand," shows that the maximum absolute deviation for each SC in each month, summed over SCs, ranges between 1,668 MW and 2,549 MW. The substantial (and unsurprising) diversity of imbalances among SCs yields this effect of the billing determinants summing to substantially larger figures over larger periods of time. Because we are proposing the billing determinant be the highest value over the most recent 12-months, the 10-month figure is the one that is most relevant to our proposal. Over the course of a year, this figure is equivalent to 54,276 MW-months (equals 12 months times 4,523 MW).

RE MID Numbers 04-24-03d.txt

On 24 Apr 2003, at 12:27, Leiber, Phil wrote:

We have some differences in billing determinants

For Resolving Energy Imbalances

Uninstructed Deviation Demand

Per MID: 54,276
Per ISO: 25,238

This is due to an update in the query we ran previously.

Number of SCs:

For purposes of the comparative analysis, we're applying the charge to
Scheduling coordinator IDs rather than Scheduling coordinators (the ISO is doing the same in its proposal currently).

Difference:
Per MID: 876 SC months
Per ISO: 984 SC months

Attached is a summary that would show the rate effects of these.

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

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

RE MID Numbers 04-24-03e.txt

From: lkirsch@svn.net
Sent: Thursday, April 24, 2003 2:19 PM
To: McGuffin, Mike
Cc: Arikawa, Ben; Pritchard, Jan; Neal, Sean; rchemphill@lrca.com
Subject: RE: MID Numbers

Mike:

The easy way of doing it is to look at a recent 12-month period (e.g., 9/01-8/02), find the maximum uninstructed deviation of each SC over the 12-month period and add up these maxima. To get an annual figure requires multiplication by 12 months. To the extent that the imbalances are "stable" over time, the result will be an accurate estimate/forecast.

Laurence

On 24 Apr 2003, at 13:29, McGuffin, Mike wrote:

Generating any numbers on a rolling 12 month basis is nearly impossible, given the current settlement system. I could get the numbers, but if we choose to implement this method, it would be necessary to calculate the data in advance of the trade year and bill a static amount on a monthly basis. I'll look into generating the numbers by SC for the customer impact...

Mike

****
Laurence D. Kirsch
Laurits R. Christensen Associates, Inc.
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fax: (415) 663-8818

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

RE MID Numbers 04-24-03c.txt

From: lkirsch@svn.net
Sent: Thursday, April 24, 2003 1:18 PM
To: Leiber, Phil
Cc: BArikawa@caiso.com; mmcguffin@caiso.com; janp@mid.org; smn@dwgp.com;
rchemphill@lrca.com
Subject: RE: MID Numbers

Phil:

If you can give us a better 1 NCP number for uninstructed deviation demand, that would helpful. The only other MID number that will be affected by that update will be the uninstructed deviation demand price.

Laurence

On 24 Apr 2003, at 12:54, Leiber, Phil wrote:

Mike,

Can you generate figures for the "ratcheted (1 NCP) demand charge" per SC based on MID's approach?

If so, please forward to me for inclusion in the customer impact analysis.

If not, please respond to Lawrence & others so we can decide what to
do instead.

Thanks...

Phil

-----Original Message-----
From: lkirsch@svn.net [mailto:lkirsch@svn.net]
Sent: Thursday, April 24, 2003 12:50 PM
To: Leiber, Phil
Cc: Pritchard, Jan; Neal, Sean; Arikawa, Ben; McGuffin, Mike; rchemphill@lrca.com
Subject: RE: MID Numbers

Phil:

Thanks for the information. We'll adopt your 984 SC-month figure. As

for the uninstructed deviation demand, the difference is not due to a data error but is instead due to our wanting a ratcheted (1 NCP) demand charge while the dataset has an unratcheted (12 NCP) demand charge. The explanation for how we derived our billing determinant is in a footnote, which I reproduce immediately below. Please let me know if you still think that there is a problem.

The change in the SC-month figure changes our numbers slightly. The revision is attached hereto.

Laurence

The footnote: The interval-by-interval dataset of uninstructed deviations show that, for the period September 2001 through June 2002: a) the maximum absolute deviation for each SC over the 10-month period, summed over SCs, is 4,523 MW; and b) the maximum absolute sum of the deviations of the SCs in any one interval is 584 MW. "Aggregated filling determinant data (revised 030423).xls," sheet "Max Uninstructed Dev demand," shows that the maximum absolute deviation for each SC in each month, summed over SCs, ranges between 1,668 MW and 2,549 MW. The substantial (and unsurprising) diversity of imbalances among SCs yields this effect of the billing determinants summing to substantially larger figures over larger periods of time. Because we are proposing the billing determinant be the highest value over the most recent 12-months, the 10-month figure is the one that is most relevant to our proposal. Over the course of a year, this figure is equivalent to 54,276 MW-months (equals 12 months times 4,523 MW).

On 24 Apr 2003, at 12:27, Leiber, Phil wrote:

We have some differences in billing determinants

For Resolving Energy Imbalances

Uninstructed Deviation Demand

Per MID: 54,276
Per ISO: 25,238

This is due to an update in the query we ran previously.

Number of SCs:

RE MID Numbers 04-24-03c.txt

For purposes of the comparative analysis, we're applying the charge to
Scheduling coordinator IDs rather than Scheduling coordinators (the ISO is doing the same in its proposal currently).

Difference:
Per MID: 876 SC months
Per ISO: 984 SC months

Attached is a summary that would show the rate effects of these.

****

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

****

****
Laurence D. Kirsch
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e-mail: LKIRSCH@LRCA.COM
voice: (415) 663-8608
fax: (415) 663-8818

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

MID Rate Design Paper and Presentation 04-24-03.txt

From: lkirsch@svn.net
Sent: Thursday, April 24, 2003 2:07 PM
To: BArikawa@caiso.com
Cc: PLeiber@caiso.com; janp@mid.org; smn@dwgp.com; rchemphill@lrca.com
Subject: MID Rate Design Paper and Presentation

Ben:

Attached please find the current update of the MID rate design paper as well as my presentation for Monday. From correspondence with Phil, I understand that improved data may be forthcoming regarding the billing determinant for uninstructed deviation demand; but I don't think it necessary to hold up the attached documents as we await that information. Therefore, please distribute these documents to the appropriate people. Thanks.

Laurence

****
Laurence D. Kirsch
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****

RE MID Numbers 04-25-03.txt

From: Leiber, Phil
Sent: Friday, April 25, 2003 10:16 AM
To: 'lkirsch@svn.net'
Cc: Arikawa, Ben; Pritchard, Jan; Neal, Sean; 'rchemphill@lrca.com'; McGuffin, Mike
Subject: RE: MID Numbers

Lawrence,

Here is the update of the MID rate summary, with the billing determinant as you discussed with Mike McGuffin.

I've also included the histogram and summary you and I discussed.

Philip Leiber, Treasurer & Director of Financial Planning
California ISO
(916) 351-2168
(916) 351-2259 (fax)

ISO bill impact analysis for ISO proposal 04-25-03.txt

From: Arikawa, Ben
Sent: Friday, April 25, 2003 2:03 PM
To: Hemphill, Ross
Cc: Pritchard, Jan
Subject: ISO bill impact analysis for ISO proposal

Ross,

The net control area load and net deviations by SC are in the tabs ETS-a and ETS-b. The rest of the bill impact analyses will be posted a
s
soon as I can add the disclaimers.

Note: The information attached is intended for the designated recipients only and is provided solely for the purpose of furthering discussion and research in the ISO's '2004 Rate Structure Project'. The information, in the form attached, is provided in response to Stakeholders' requests and as such does not necessarily indicate the ISO's concurrence in, or support for, its usefulness in developing a rate methodology. No implications may be drawn regarding the ISO's position on any subject in the Project from either the inclusion or exclusion of any specific data. The ISO does not warrant the completeness or accuracy of the data. The ISO is not necessarily the originator of the data.

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Spreadsheets you asked for 04-28-03.txt

From: Arikawa, Ben
Sent: Monday, April 28, 2003 5:00 PM
To: Kirsch, Laurence
Subject: Spreadsheets you asked for

Laurence

Here are the spreadsheets that you asked for last week. Sorry I didn't

get these to you last week. I left a bit early on Friday.

Note: The information attached is intended for the designated recipients only and is provided solely for the purpose of furthering discussion and research in the ISO's '2004 Rate Structure Project'. The information, in the form attached, is provided in response to Stakeholders' requests and as such does not necessarily indicate the ISO's concurrence in, or support for, its usefulness in developing a rate methodology. No implications may be drawn regarding the ISO's position on any subject in the Project from either the inclusion or exclusion of any specific data. The ISO does not warrant the completeness or accuracy of the data. The ISO is not necessarily the originator of the data.

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California Independent
System Operator

Proposed Agenda
2004 GMC Rate Structure Project
Monday, April 28, 2003
Location: California ISO, Folsom
10:00 a.m. to 3:00 p.m.

Public Session (Conference Call-in #1-888-788-6681Passcode: 921065)

1. Introductions/roll call
2. SCE proposal update
3. MID proposal update
4. ISO proposal update
   a. Cost components
   b. Customer Service cost recovery
   c. Example rate calculation
5. Discussion of timeline

Confidential Session (a separate number will be distributed to parties that have executed the Non-Disclosure Agreement)

1. Discussion of billing impacts
   a. SCE
   b. MID
   c. ISO

Created by: Ben Arikawa CAISO LSUPDT: 04/24/03

Note: This document is circulated by the sender solely for the express purpose of informing discussion. Therefore, none of the contents may be regarded by the reader as any form of offer, undertaking, policy, proposal or commitment by the sender, author or the California ISO.



Further Update on Modesto's GMC Proposal

Laurence D. Kirsch
Laurits R. Christensen Associates, Inc.
www.LRCA.com

CAISO 2004 GMC Rate Design Project Meeting

Folsom, California
April 28, 2003

Exh. No. ISO- 258, Page 1 of 9

Engineering Foundation:
System Operators Minimize Costs Subject to Constraints

- System Constraints:
  - power balance
  - transmission flow limits
  - voltage limits
- Private Constraints:
  - generator output limits
  - generator ramping limits

Exh. No. ISO- 258, Page 2 of 9

Our Proposed Functions

- Functions that *directly* manage the system constraints:
  - Resolving Energy Imbalances
  - Managing Transmission Flows
- Functions that *indirectly* help manage the system constraints:
  - Administering Markets
  - Forward Scheduling

Exh. No. ISO- 258, Page 3 of 9

Recent Changes: Adopt Elements of the ISO's Proposal

- Set customer charge at $500/SC-month
- Add Scheduling Function
  - Service and billing determinant are defined as per the ISO
  - Numbers are as per the ISO
  - Dollars assigned to the Scheduling Function are taken (proportionately) from the Resolving Energy Imbalances and Managing Transmission Flows functions

Exh. No. ISO- 258, Page 4 of 9

Cost Assignment Among Functions

Function	Dollars	Percent	Dollars	Percent
Resolving Energy Imbalances	$ 42,433,238	17.9%	$ 37,701,064	15.9%
Managing Transmission Flows	$128,296,398	54.0%	$113,988,724	48.0%
Administering Markets	$ 66,870,735	28.1%	$ 66,870,735	28.1%
Forward Scheduling			$ 19,039,848	8.0%
Totals	$237,600,371	100.0%	$237,600,371	100.0%

Recent Changes: Imitate Cost

- In the Resolving Energy Imbalances and Managing Transmission Flows functions:

$$\frac{Demand}{Energy} = \frac{Core\ Reliability\ Services}{E\ \&\ T\ Services + Congestion\ Mgt}$$

$\Rightarrow$ *65.9% Demand*
34.1% Energy

Exh. No. ISO- 258, Page 6 of 9

Recent Changes:

- Maximum power withdrawals
- Trading volumes

Exh. No. ISO- 258, Page 7 of 9

Our Updated Rate Design

Function	Dollars	Quantity		Rate	
Resolving Energy Imbalances					
uninstructed deviation energy	$12,805,442	16,506,418	MWh	$0.78	/MWh net deviation
uninstructed deviation demand	$24,772,622	54,276	MW-months	$456.42	/MW-month 1NCP net deviation
number of SCs	$123,000	984	SC-months	$125	/SC-month
	$37,701,064				
Managing Transmission Flows					
power withdrawals	$38,718,087	242,456,619	MWh	$0.16	/MWh net load
maximum power withdrawals	$74,901,637	534,042	MW-months	$140.25	/MW-month 12NCP net load
number of SCs	$369,000	984	SC-months	$375	/SC-month
	$113,988,724				
Administering Markets					
Trading volumes	$66,870,735	29,327,169	MWh	$2.28	/MWh traded
Scheduling					
Forward Scheduling	$19,039,848	12,819,845	schedules	$1.49	/schedule HA
Totals	$237,600,371				

Exh. No. ISO- 258, Page 8 of 9

Next Steps

- Update for any relevant amendments to the ISO GMC proposal since 4/9/03
- Present rate design to ISO

Exh. No. ISO- 258, Page 9 of 9

CHRISTENSEN ASSOCIATES

Laurits R. Christensen Associates, Inc.
4610 University Avenue, Suite 700
Madison, Wisconsin 53705-2164

Voice 608.231.2266 Fax 608.231.2108

TO: Ben Arikawa

FROM: Ross Hemphill & Laurence Kirsch

DATE: 4/24/03

SUBJECT: Rate Design of the California ISO's Grid Management Charge

Attached please find our revised proposal for designing the GMC. This revision reflects information provided by the ISO since the March 7th draft, and also reflects certain elements of the ISO's rate proposal of April 9. The most significant revisions are as follows:

- We have set our customer charge at $500 per SC per month, exactly as proposed by the ISO.
- We have adopted the ISO's Forward Scheduling service, exactly as proposed by the ISO with respect to the definition of the service, the definition of the billing determinant, the cost allocation, and the billing determinant quantities.
- We have allocated costs between our demand and energy charges in accordance with the ISO's proportional cost split between: a) its Core Reliability Services; and b) its Energy and Transmission Service plus Congestion Management Service.

The results appear in the attached paper, and will be summarized in our presentation next Monday.

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 provide details of the rate design proposal made by Dr. Kirsch in the California ISO's 2001 Grid Management Charge proceeding.[1] These details include the best numbers that it is possible to produce at this time, given the availability of the underlying data.

In the spirit of trying to find common ground with the tentative positions expressed by the ISO and the CPUC in their recent presentations of February 19 and April 11,[2] the rate design proposal that we make in this paper reflects two major principles:

- The customers who use the ISO's services should pay for those services to the extent practical.
- Unavoidable fixed costs should be recovered through fixed charges (i.e., demand and customer charges) to an extent consistent with economic efficiency.

To simultaneously adhere to these two principles, we functionalize costs according to the services the ISO provides to customers; and we classify the 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.

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]

---

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

[2] Phil Leiber, *ISO Conceptual Rate Structure*, 2004 GMC Rate Structure Project Meeting, San Francisco, February 19, 2003; Ben Arikawa, *California ISO Rate Structure Proposal*, April 11, 2003; and Karen Shea, *CPUC/EOB Modifications to CAISO 2004 GMC Rate Structure Proposal*, April 11, 2003. We take no position on the issues raised by SCE in its proposals of February 19 and April 11.

[3] The engineering literature repeatedly states that system operators aim to minimize some set of system 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;

- *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 two of these other services merit 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.
- *Forward scheduling* so that SCs can set and update their schedules, and so that the ISO can confirm that the schedules are consistent with the power system's physical capabilities.

1.2. Cost Assignments for Our Proposed Functions

In making our initial cost assignment, we considered only three functions: Resolving Energy Imbalances, Managing Transmission Flows, and Administering Markets. We excluded Managing Voltages because of the difficulty of reasonably measuring customer's use of this service; and we excluded Scheduling because, in the 2001 Grid Management Charge proceeding, FERC Staff raised questions concerning whether separate scheduling charges were consistent with FERC policy.[4]

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.

[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.

To facilitate the assignment of costs to our proposed functions, the ISO provided to us 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" departments to our three functions. The result is that the ISO's costs were initially assigned to our functions as follows:[5]

TABLE 1A
OUR INITIAL 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%

Subsequent to our initial assignment, the ISO proposed a separate $19 million charge for what it calls "Forward Scheduling." Because we agree that a scheduling charge is warranted in principle and because we wish to find common ground with the ISO, we adopt the ISO's Forward Scheduling function exactly as proposed by the ISO with respect to its definition, its billing determinant, and its costs. Because our initial cost assignment placed scheduling costs within the Resolving Energy Imbalances and Managing Transmission Flows functions, we have removed $19 million of costs from these functions and have done so in proportion to the total costs initially assigned to these functions. The resulting cost assignment is as follows:

TABLE 1B
OUR REVISED ASSIGNMENT OF ISO COSTS

Function	Dollars	Percent
Resolving Energy Imbalances	$ 37,701,064	15.9%
Managing Transmission Flows	113,988,724	48.0%
Administering Markets	66,870,735	28.1%
Forward Scheduling	19,039,848	8.0%
Totals	$237,600,371	100.0%

[5] 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.

2. CLASSIFYING COSTS AND DESIGNING RATES[6]

In this section, for each of the four 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 imbalance 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:

- *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 are proposing a non-coincident peak measure 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.[7]
- *The customer measure* is the number of SCs.

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.[8]

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

[7] 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.

[8] 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.

TABLE 2
BILLING DETERMINANTS
FOR THE RESOLVING ENERGY IMBALANCES FUNCTION

Billing Determinant	Quantity	Data Period
Uninstructed deviation energy	16,786,796 MW-intervals	9/01-8/02
Uninstructed deviation demand (most recent 12 months)[9]	54,276 MW	9/01-6/02
Number of SCs	984 SC-months	9/01-6/02

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[10] 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.

For the customer charge, we propose to exactly follow the ISO proposal 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.[11]

---

[9] The interval-by-interval dataset of uninstructed deviations show that, for the period September 2001 through June 2002: a) the maximum absolute deviation for each SC *over the 10-month period*, summed over SCs, is 4,523 MW; and b) the maximum absolute sum of the deviations of the SCs *in any one interval* is 584 MW. "Aggregated filling determinant data (revised 030423).xls," sheet "Max Uninstructed Dev demand," shows that the maximum absolute deviation for each SC *in each month*, summed over SCs, ranges between 1,668 MW and 2,549 MW. The substantial (and unsurprising) diversity of imbalances among SCs yields this effect of the billing determinants summing to substantially larger figures over larger periods of time. Because we are proposing the billing determinant be the highest value over the most recent 12-months, the 10-month figure is the one that is most relevant to our proposal. Over the course of a year, this figure is equivalent to 54,276 MW-months (equals 12 months times 4,523 MW).

[10] Equals $30,670,132 plus $7,667,533 plus $10,017,448.

[11] 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.

TABLE 3
RATES FOR THE RESOLVING ENERGY IMBALANCES FUNCTION

Billing Determinant	Cost	Quantity	Rate
Uninstructed deviation energy	$12,805,442	16,506,418 MWh	$0.78 / MWh net deviation
Uninstructed deviation demand (most recent 12 months)	$24,772,622	54,276 MW	$456.42 / MW-month 1 NCP net deviation
Number of SCs	$123,000	984 SC-months	$125 / SC-month

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.

Although we find the case for a demand charge less compelling for the Managing Transmission Flows function than for the Resolving Energy Imbalances function, we recognize that this is a service that only the ISO can provide, and that it incurs substantial fixed costs to be able to provide it. Hence, we propose that, in each month the billing determinants for this function include an energy measure, a demand measure, and a customer measure. For each SC in each month, the proposed billing determinants are as follows:

- *The energy measure* is the sum of the SC's power withdrawals from the ISO-controlled grid.
- *The demand measure* is the SC's maximum hourly power withdrawal from the ISO-controlled grid during the current month. This is a non-coincident peak measure for each separate month (i.e., 12 NCP). We propose a non-coincident peak measure because customers have much better access to information about their own peak power withdrawals than about total power withdrawals, and because the costs of managing transmission flows is more related to local peaks than to system peaks. A monthly demand charge would minimize the inequities that might arise from customer switching among SCs, a concern expressed by SCE.[12]
- *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.

[12] Memorandum of Bert Hansen, February 21, 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
Maximum power withdrawals	534,042 MW-months	9/01-8/02
Number of SCs	984 SC-months	9/01-6/02

As described in Section 2.1, we establish rates by allocating 34.1% of non-customer costs to energy charges and 65.9% of non-customer costs to demand charges; and we set the customer charge at $375 per SC per month. Table 5 shows the resulting costs and rates.

TABLE 5
RATES FOR THE MANAGING TRANSMISSION FLOWS FUNCTION

Billing Determinant	Cost	Quantity	Rate
Power withdrawals	$38,718,087	242,456,619 MWh	$0.16 / MWh net load
Maximum power withdrawals	$74,901,637	534,042 MW-months	$140.25 / MW-month 12 NCP net load
Number of SCs	$369,000	984 SC-months	$375 / SC-month

2.3. Administering Markets

The costs of administering markets should be recovered from the customers who trade in these markets. Ideally, measurement of the customers' use of the markets should be according to some combination of the volumes (MWhs) and values (dollars) traded. The measurement should probably differ by the service traded (e.g., energy, spinning reserves, financial transmission rights), though such differences might be captured sufficiently by measures of value 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, the 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.

Hence, we propose that, in each month 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 (e.g., energy, spinning reserves, transmission rights).

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 MWh of energy exactly the same weight as (for example) a MW-h of spinning reserves. Although the experience of competitive commodity markets leads us to believe that differentiation among services is warranted, we use the aggregate MWhs figure for the immediate purpose of this proposal.

TABLE 6
BILLING DETERMINANTS
FOR THE ADMINISTERING MARKETS FUNCTION

Billing Determinant	Quantity	Data Period
Trading volumes	29,327,169 MWh	9/01-8/02

Table 7 shows the consequent rates.

TABLE 7
RATES FOR THE ADMINISTERING MARKETS FUNCTION

Billing Determinant	Cost	Quantity	Rate
Trading volumes	$66,870,735	29,327,169 MWh	$2.28 / MWh

2.4. Forward Scheduling

For this function, we adopt the ISO's proposal without amendment. The rates are shown in the following table.

TABLE 8
RATES FOR THE FORWARD SCHEDULING FUNCTION

Billing Determinant	Cost	Quantity	Rate
Schedules	$19,039,848	12,819,845 schedules	$1.49 / schedule

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.

SCE GMC PROPOSAL RATES

Services:

CAS = Contol Area Services
DDES = Dynamic Dispatch Export Service
SS = Scheduling Service
MOS = Market Operations Service
RMOS = Real-Time Market Operations Service

GMC SERVICE COMPONENT	ALLOCATED COSTS	BILLING DETERMINANTS	RATE		Check: Revenue
CAS	$167,320,035	242,451,790	$0.6892	$/MWh	$167,092,606
DDES	--	3,300,000	$0.0689	$/MWh	$227,429
SS	$16,270,959	241,746,847	$0.0545	$/MWh	$13,184,723
MOS	$37,136,426	56,587,298	$0.7108	$/MWh	$40,222,662
RMOS	$16,872,951	16,786,796	$1.0051	$/MWh	$16,872,951
Total:	$237,600,371				$237,600,371

Notes on Rate Calculations:

1) DDES rate is set equal to 10% of CAS rate
This is accomplished by simultaneously calculating the CAS rate and DDES rates:
CAS rate = CAS costs / ((BDcas+ (0.1*BDddes)), and DDES rate = 0.1 * CAS rate
2) All costs allocated to SS are also collected from MOS
This is allomplished by simultaneously calculating the SS and MOS rates:
SSrate = SS costs/(BDss+BDmos), and
MOSrate = (SS costs + MOS costs - SS revenues)/BDmos

Billing Determinants:

Service	BD Volume	BD Description
CAS	242,451,790	MWh of Control Area Load (Exclusive of retail behind-tl
DDES	3,300,000	MWHs of gen dynamically dispatched to other Control
SS	241,746,847	MWh of scheduled energy + self-provided AS (final sch
MOS	56,587,298	MWh of pur/sales of energy + AS
RMOS	16,786,796	MWh of uninstructed imbalance energy

Notes on Billing Determinants:

1) DDES volume is based on SCE's 5,400,000 annual MWh output from 56% share of 34% owned by Nevada (14%) and SRP (20%)
2) All other BDs based on March 5, 2003 ISO "Aggregated Billing Determinant Data"
3) Control Area Load = 251,615,170 Control Area Gross Load (MWh)

-3,300,000	DDES Energy
-5,863,380	BTM load served by BTM gen (MW
242,451,790	

4) SS BD is:

237,746,847	Scheduled load (MWh)
4,000,000	Self-provided AS (MWh) **Preliminary estimate**
241,746,847	

5) MOS BD is based on ASREO volumes less uninstructed deviations

73,374,094	ASREO
-16,786,796	Uninstructed imbalance energy
56,587,298	

6) RMOS BD is equal to "sum of absolute net uninstructed deviations"

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Areas over non-ISO T
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CALIFORNIA ISO

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System Operator

Components of Rates
California ISO Rate Proposal

April 28, 2003
2004 GMC Rate Structure Project

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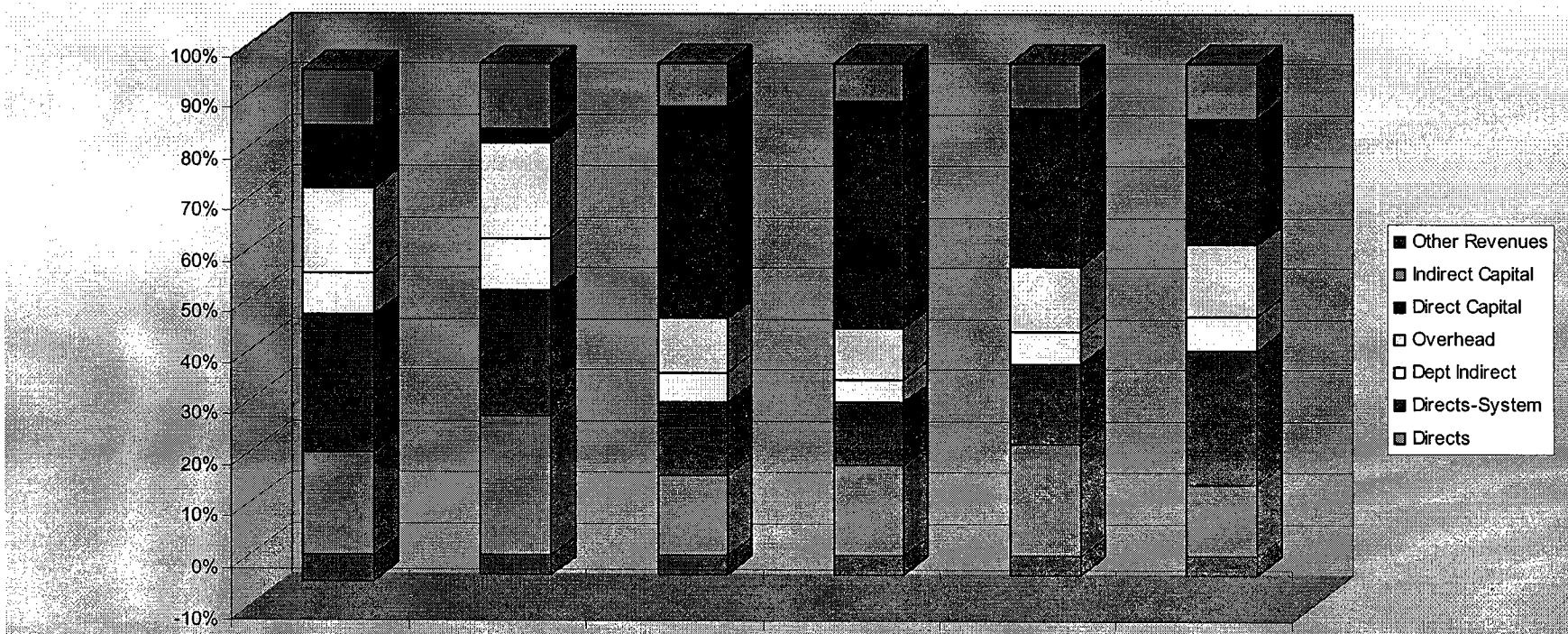
Exh. No. ISO- 261, Page 1 of 8

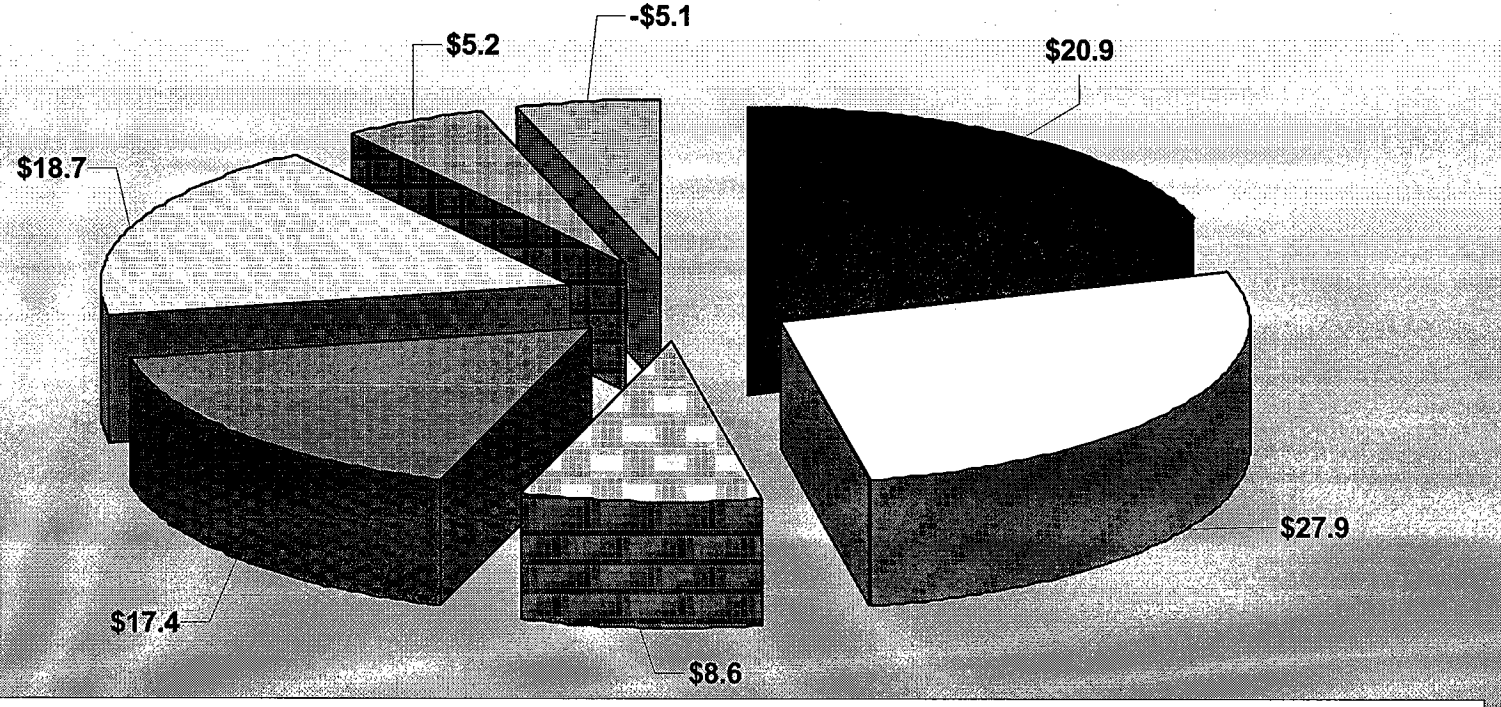
Components of Proposed Rates
ISO Rate Proposal



Created By: bta

LST UPDT: 04/11/2003

Components of Core Reliability Services ($93.5 million)
(in millions)



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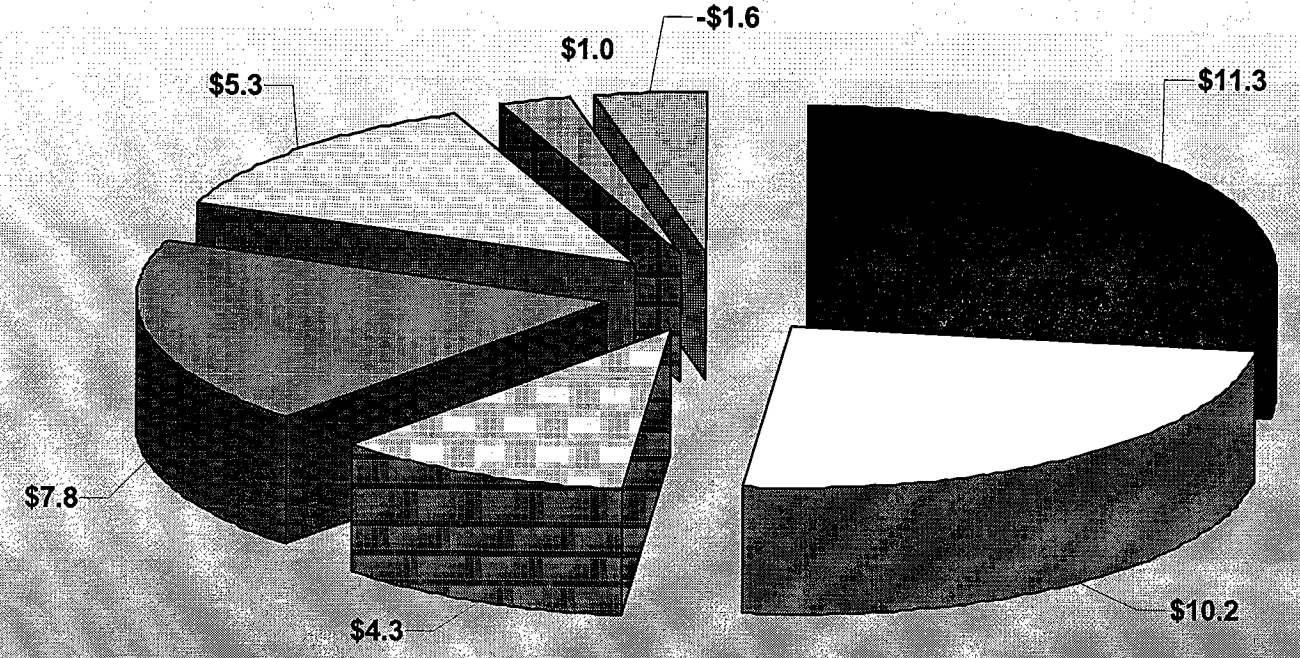
Components of Energy & Transmission Services ($38.3 million)
(in millions)



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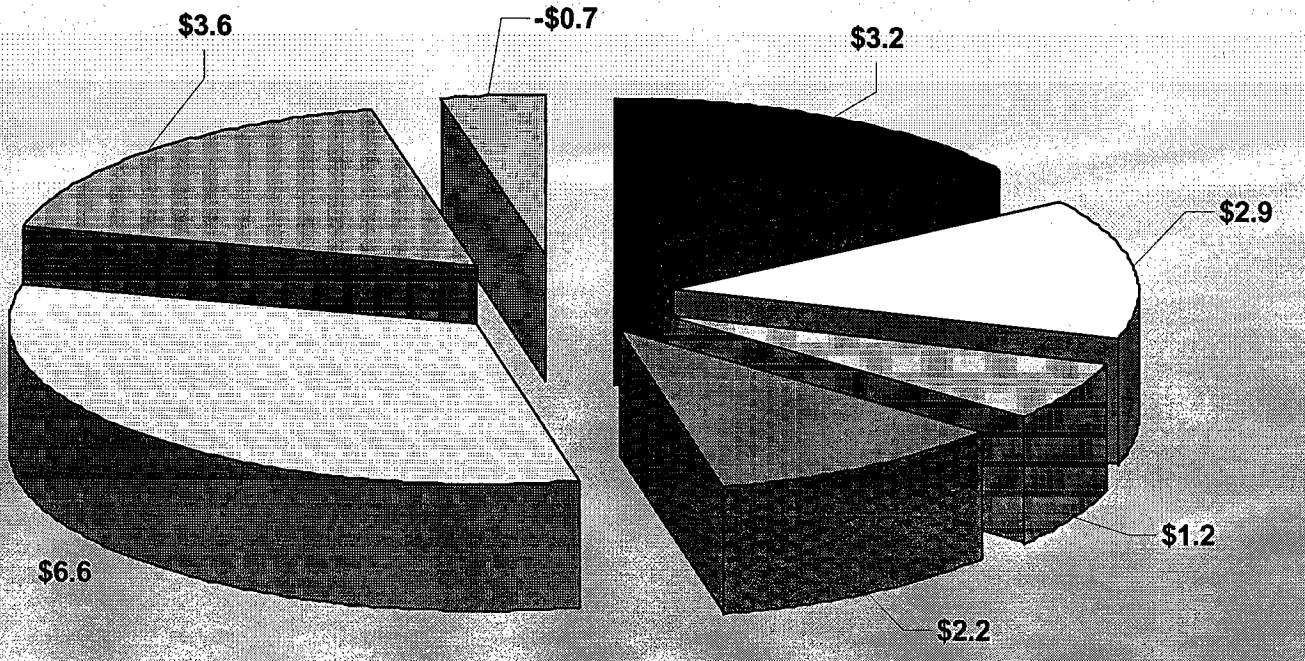
Components of Forward Scheduling ($19.0 million)
(in millions)



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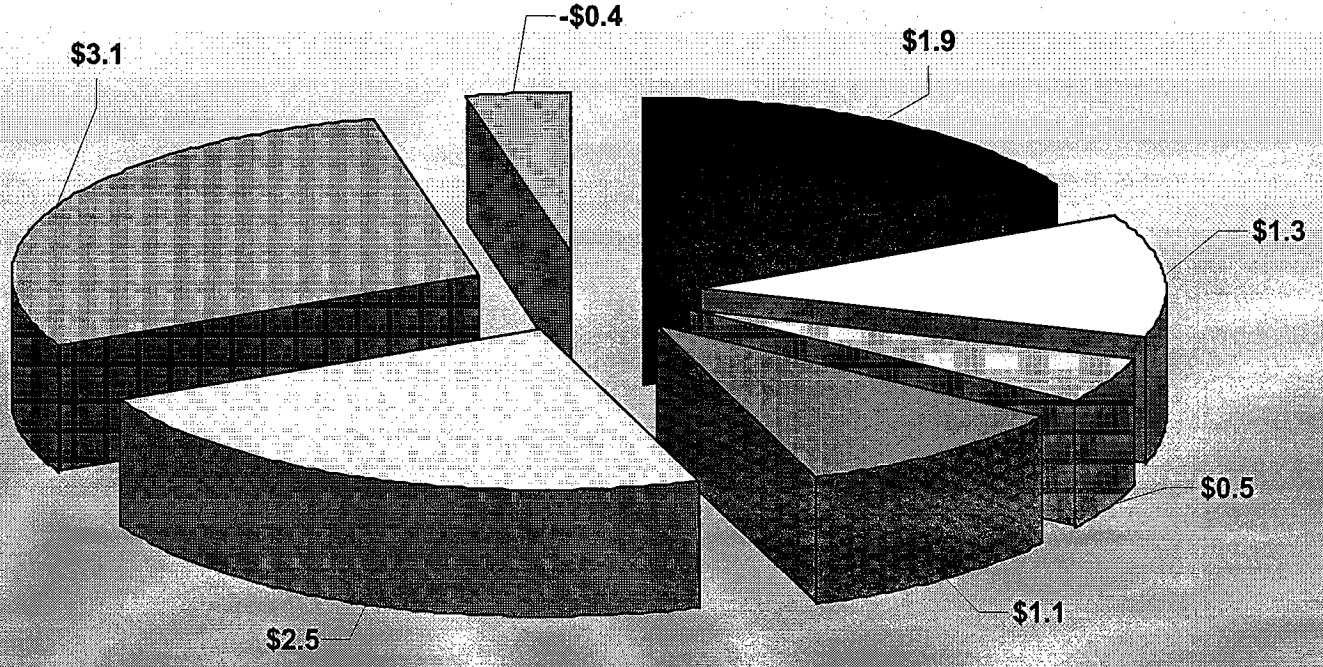
Components of Congestion Management ($10.0 million)
(in millions)



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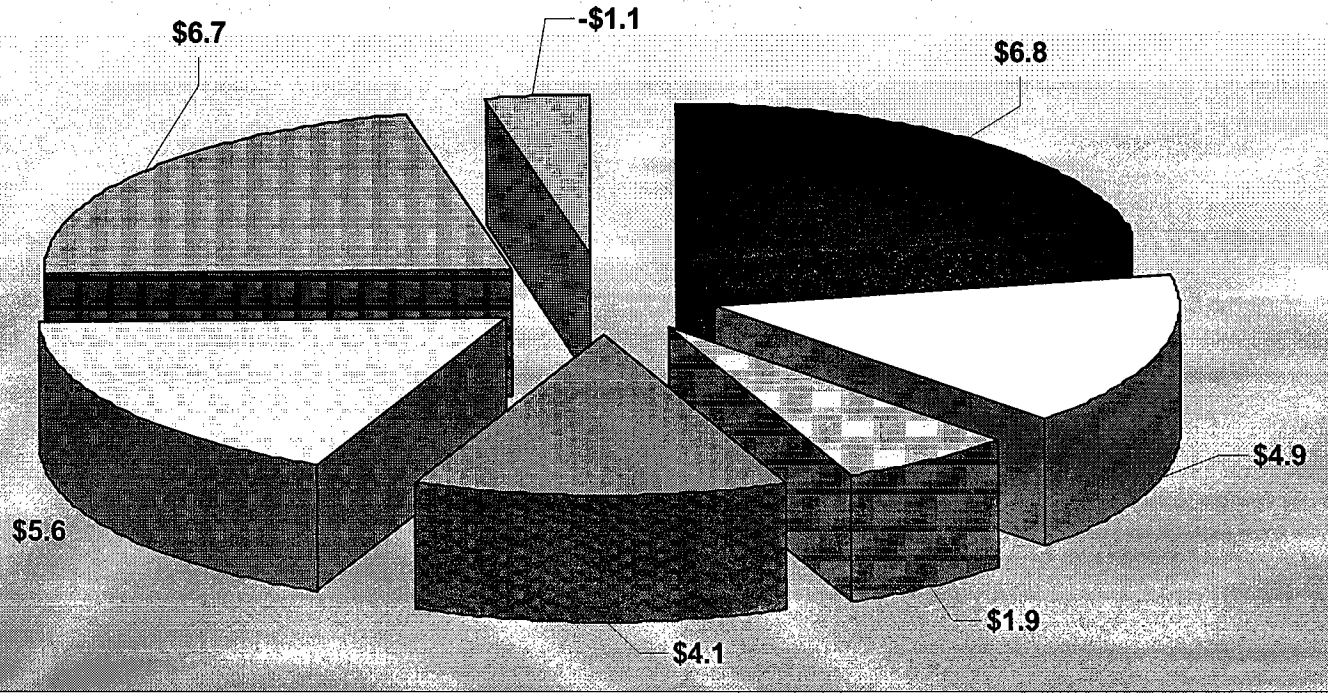
Components of Market Usage ($28.8 million)
(in millions)



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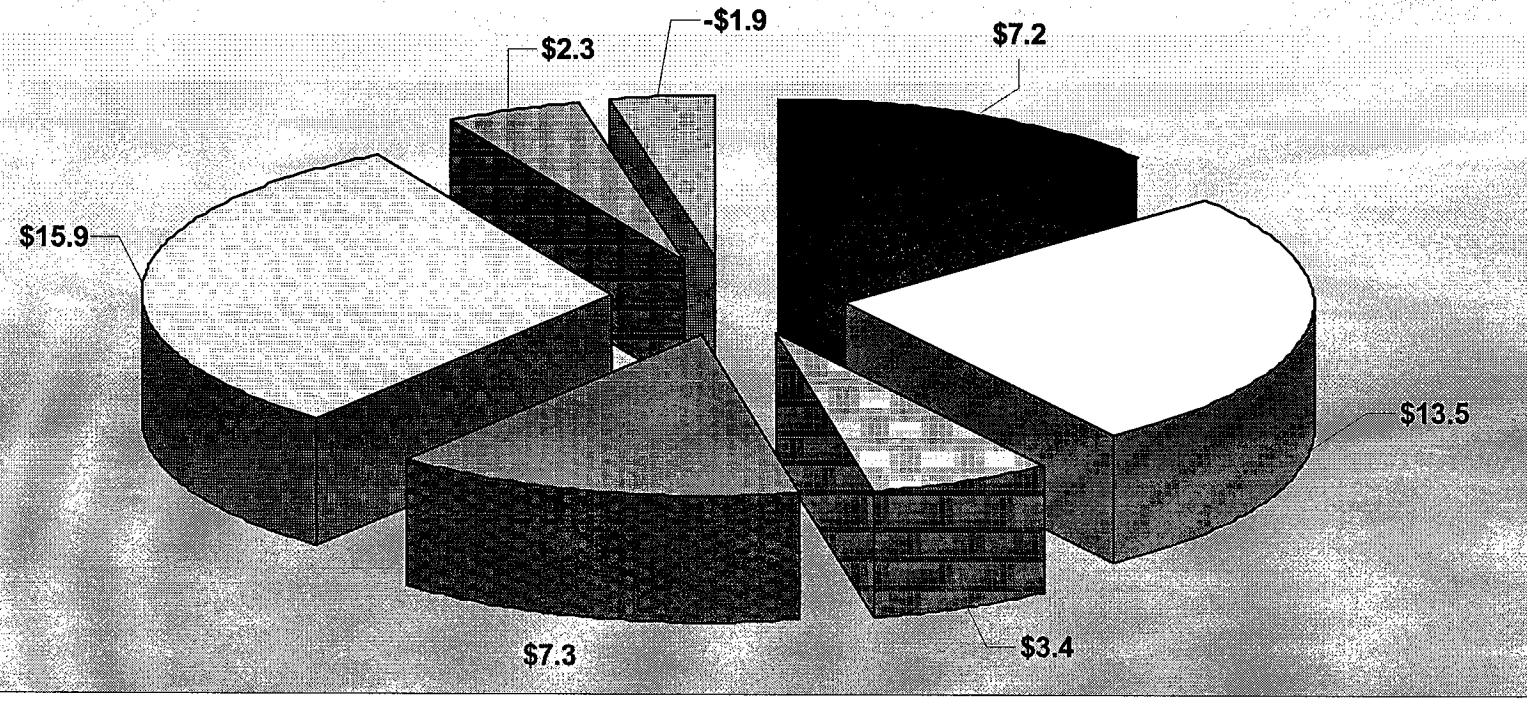
Components of Customer Service ($47.9 million)
(in millions)



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Customer Service Cost Recovery

April 28, 2003

2004 GMC Rate Structure Project

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Exh. No. ISO- 262, Page 1 of 5

Other ISOs' Customer Charges

- ISO-NE - $5,000/year
- NYISO – Tiered for small consumers
  - $100: 0 - 499 MWh/year
  - $500: 500 – 1999 MWh/year
  - $1,000 : greater than 2000 MWh/year
  - $5,000: all other companies
- PJM - $5,000/year
- ERCOT - $2,000/year full members
- Ontario IMO Tiered
  - $0: 0 – 99 MWh/year
  - $1,000: 100 to 2,999 MWh/year
  - $8,000: greater than 3,000 MWh/year

Exh. No. ISO- 262, Page 2 of 5

Options Reviewed by ISO

- Pro rata assignment
- Direct/indirect assignment
- Fixed charge
  - Single fully loaded charge
  - Tiered fully loaded charge
    - Scaled by
      - Load and exports or generation and imports
      - Market transactions and schedules
      - Billable volumes on Final Settlement Statement
      - Line items on Final Settlement Statement

Exh. No. ISO- 262, Page 3 of 5

Some Criteria

- Understandable and easy to explain
- Easy to administer
- Data accessible in Settlements System

Exh. No. ISO- 262, Page 4 of 5

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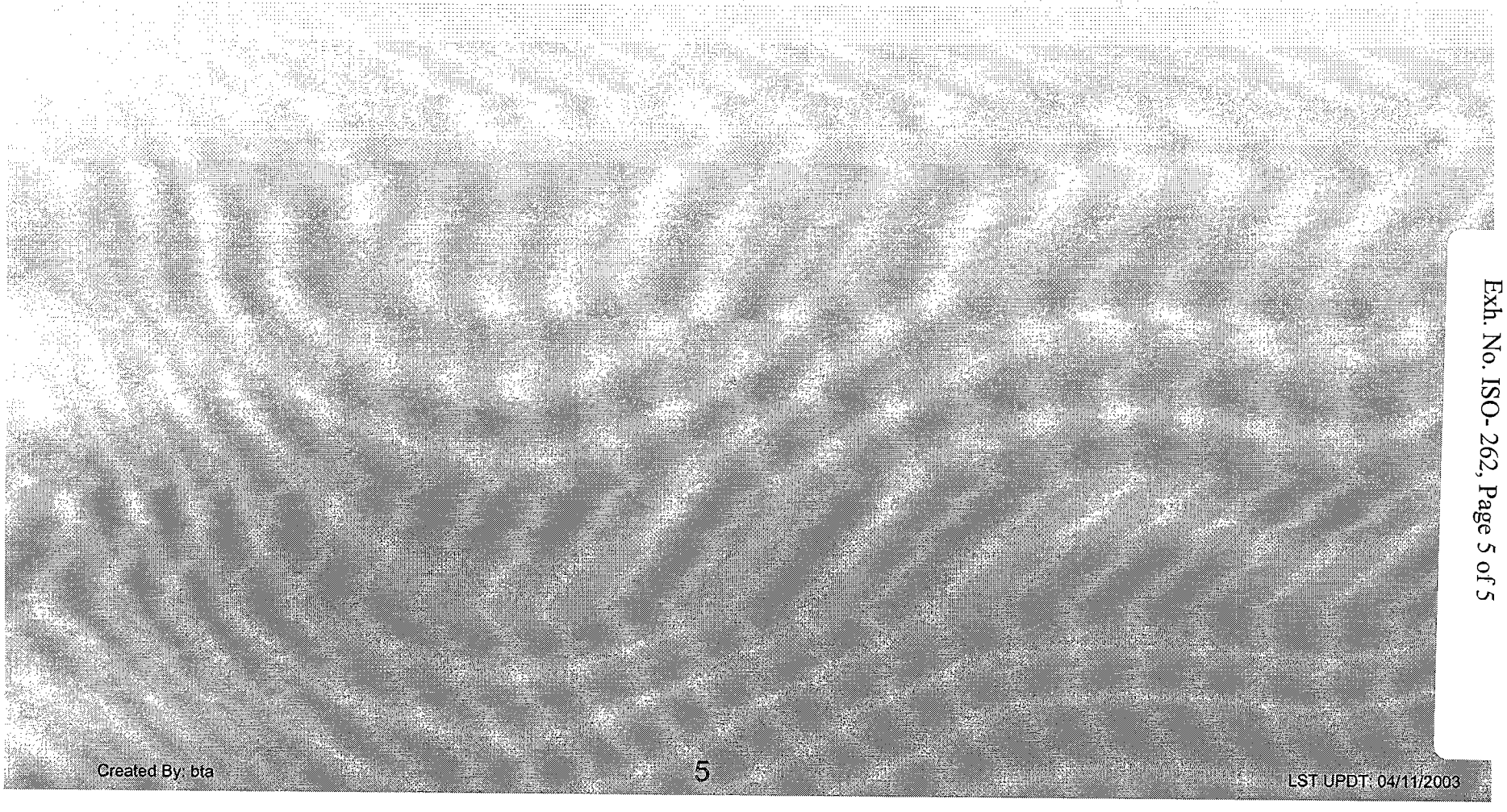
Other Options?



Exh. No. ISO- 262, Page 5 of 5

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Example Rate Calculation

April 28, 2003

2004 GMC Rate Structure Project

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Exh. No. ISO- 263, Page 1 of 16

Overview

- Example transaction includes SC-SC energy trade, flow across zonal interfaces, metered Load, Export volume, A/S allocation, and schedule deviations.
- Assume same transaction 24 x 7 for one month.
- Calculate charges with 2003 rates.
- Calculate charges with proposed rates.

Exh. No. ISO- 263, Page 2 of 16

Assumptions used in Example

- Scheduling Coordinator transaction for 1 hour;
  - Metered Energy consumption of 318 MWh (schedule = 300 MW)
  - Non-coincident demand of 518 MW-month (includes metered Load and Exports)
  - 200 MWh of scheduled exports from SP15 to AZ3
  - 500 MWh SC trades between NP15 and SP15 (through ZP26, net)
  - 35 MW A/S Operating Reserve allocation
  - 18 MWh Load deviation
  - Real-time Operational Adjustment to Export Schedule resulting in 15 MWh deviation (schedule was cut, 185 MWh were actually exported)
  - 3 final hour-ahead schedules

Control Area Services (CT 521) Calculation

CASC = CASR * (CAGL + SE)

- **CASC = Control Area Service Charge due ISO**
- **CASR = Control Area Service Rate = $0.569/MWh**
- **CAGL = SC's Control Area Gross Load = 300 MWh**
- **SE = SC's Exports = 185 MWh**

$285.70 = $0.568 * (318 MWh + 185 MWh)

Exh. No. ISO- 263, Page 4 of 16

Congestion Management (CT 522) Calculation

IZSC = IZSR * NFU

- **IZSC= Congestion Management Charge due ISO**
- **IZSR = Congestion Management Charge Rate = $0.320/MWh**
- **NFU = Final hour-ahead net inter-zonal New Firm Use flow of Scheduling Coordinator j along path p on operating date t and operating hour h. New Firm Use refers to transmission usage without Existing Transmission Contracts.**

$384.00 = $0.320* [200 MWh export + (500 MWh *2 zonal interfaces)]

Exh. No. ISO- 263, Page 5 of 16

ASREO (CT 524) Calculation

MOC = MOR * [ASP + ASS + IIE + UIE)

- **MOC = Market Operations Charge due ISO**
- **MOR = Market Operations Rate = $1.296**
- **ASP = Ancillary Service purchases from SC = 0 MWh**
- **ASS = Ancillary Service sales (allocation) to SC = 35 MW**
- **IIE = Instructed Imbalance Energy for SC. This value is the net of all IIE per SC per location per interval = 0 MWh**
- **UIE = Uninstructed Imbalance Energy = 18 MWh + 15 MWh = 33 MWh**

$88.13 = $1.296* (0 MWh + 35 MW + 0 MWh + 33 MWh)

Total GMC

- **$285.70 + $384.00 + $88.13 = $757.83/hr**
- **Assume identical transaction each hour and 730 hours in average month**
- **Monthly charge in 2003 = 730 x $757.83 = $553,216**

Proposed Rates – Core Reliability Services

- Determinant = Gross non-coincident peak demand, MW (Load + Exports)
- 318 MW Load + 185 MW Exports = 503 MW x $175.16/MW-Month = $88,105.48/month

Proposed Rates – Energy and Transmission Services - Load

- Determinant = Net Control Area Load + Exports
- (318 MWh + 185 MWh) x $.126/MWh = $63.38/hr

Proposed Rates – Energy and Transmission Services - Deviation

- Determinant = Absolute value of net uninstructed deviations by settlement interval (MWh)
- (18 MWh – 15 MWh) x $.465/MWh = $1.40/hr

Proposed Rates - Scheduling

- Determinant = Number of Final Hour-Ahead Schedules returned by Scheduling Infrastructure
- 3 final H/A schedules x $1.497/schedule = $4.49/hr

Proposed Rates – Congestion Management

- Determinant = Hour-ahead net inter-zonal New Firm Use flow (excludes ETCs)
- [200 MWh export + (500 MWh * 2 zonal interfaces)] x $.114/MWh = $136.80/hr

Proposed Rates – Market Usage

- Determinant = Purchases and sales of Ancillary Services, instructed energy, and absolute value of net uninstructed deviations.
- [0 MWh + 35 MW + 0 MWh + (18 MWh – 15 MWh)] x $.628/MW & MWh = $20.72/hr

Proposed Rates – Customer Service

- Determinant = Minimum of $500/month fixed charge + $.0289 per absolute value of all system generated billable quantities from final settlement statements for previous month.

Exh. No. ISO- 263, Page 14 of 16

Total Proposed GMC

- **$63.38 + $1.40 + $4.49 + $136.80 + $20.72 = $226.79/hr**
- **Assume identical transaction each hour and 730 hours in average month**
- **Proposed monthly charge = (730 x $226.79) + $88,105.48 = $253,662 (Excluding Customer Service Charge)**

Questions?

Market Participants and Scheduling Coordinators:

ISO 2004 GMC Rate Structure Project

SC Data Release

Pursuant to an Initial Decision issued on May 10, 2002 in Docket No. ER01-313, FERC Administrative Law Judge Bobbie J. McCartney directed the California ISO to undertake a comprehensive review of its GMC rate structure during 2003. That project must permit effective stakeholder participation, including stakeholder testing of alternative methods of rate design. To facilitate that review, the ISO has been asked to release certain SC-related data to specified stakeholders. The SC specific data in question are non-coincident peak demand, load and exports, number of schedules, Net Interzonal Scheduled flows, purchases and sales of Ancillary Services (including self-provided amounts), Supplemental Energy and Imbalance Energy, billable quantities on a Final Settlement Statement, Scheduled load and exports, and net uninstructed deviations by 10 minute interval for September 2001 through August 2002.

To the extent that this request seeks information that is confidential and/or commercially sensitive under ISO Tariff Section 20.3.2., the ISO will require confidential treatment for such information. **Any stakeholder acquiring access to such data must first have executed the ISO's Confidentiality Agreement for this Project.** In addition the ISO has removed all means of identifying specific SCs. **Finally, the ISO does not currently intend to release any SC-related data for this Project until six months after the passage of the Trade Dates in question.**

The ISO plans to produce appropriate materials at the close of business April 25, 2003, unless the ISO receives by noon (PDT) on that date a FERC or other appropriate order that prohibits disclosure. If you have any questions, please contact ISO Senior Regulatory Counsel, Anthony Ivancovich, at aivancovich@caiso.com

Client Relations Communications
CRCommunications@caiso.com <

California Independent
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Proposed Agenda and Draft Meeting notes
2004 GMC Rate Structure Project
Monday, April 28, 2003
Location: California ISO, Folsom
10:00 a.m. to 3:00 p.m.

Public Session (Conference Call-in #1-888-788-6681Passcode: 921065)

1. Introductions/roll call
2. SCE proposal update
3. MID proposal update
4. ISO proposal update
   a. Cost components
   b. Customer Service cost recovery
   c. Example rate calculation
5. Discussion of timeline

Confidential Session (a separate number will be distributed to parties that have executed the Non-Disclosure Agreement)

1. Discussion of billing impacts
   a. SCE
   b. MID
   c. ISO

Please see below for meeting notes.

Created by: Ben Arikawa CAISO LSUPDT: 05/05/03

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Please see the last page for the list of attendees.

The discussion began with Bert Hansen of SCE providing an update to the SCE rate proposal. Bert had completed the cost assignment and had developed rates. The rate calculations had been posted on the ISO website and were distributed in hardcopy during the meeting.

Many of the questions to Bert concerned the Dynamic Dispatch Export Service (DDES). Several had questioned why Bert had set the DDES rate to 10 percent of SCE's Control Area Services rate. Bert had based this on his review of the services that the ISO stated it provided in its current Control Area Services function.

There were additional questions about the mechanics of the dispatch instructions to Mohave and what entity issued those instructions. Deane Lyon and Jan Pritchard provided brief explanations of the process.

David Cohen asked why the Real Time Market Operations Services (RMOS) charge was so small relative to the Market Operations charge. Ben Arikawa noted that Bert had assigned the Real Time Grid Operations costs to the RMOS and not all market functions.

There was a discussion of the assignment of costs within each function.

On the continuing discussion of the DDES, Bert explained on which transmission paths Mohave power flowed to Nevada Power and Salt River Project.

David Cohen asked that the ISO provide the amount of costs that other entities would pay if the DDES charge were implemented in either the SCE or ISO proposals. MID stated that it believed Mohave would not need an exemption as its exports to Nevada Power and Salt River Project would not be charged under MID's proposal.

There was some discussion about SCE's desire to address the DDES charge through negotiations with the ISO. Most parties wanted to see cost data prior to agreeing to any separate settlement.

Laurence Kirsch, Christensen Associates, was next, giving an update on the MID proposal. MID had adopted the ISO's scheduling function and incorporated that into its proposal. They had also modified the customer and demand charges to reflect the cost allocations used in the ISO proposal.

There had also been some updates to billing determinants. This began a discussion of the changes in the non-coincident demand and scheduling billing determinants. The ISO had made some changes to billing determinants subsequent to those distributed to MID.

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There was a discussion of the ratchet mechanism that MID employed in its demand charge. David Cohen questioned whether any other ISOs used a ratchet mechanism. Mike McGuffin pointed out that using any rolling average would be difficult in the ISO Settlement System.

There was a discussion of the impact of charges to net deviations to Metered Sub-Systems (MSSs). Debi Le Vine explained how MSSs are currently charged for deviations.

David Cohen asked if the ISO had accounted for price elasticity in developing its scheduling billing determinant. The ISO had not.

Laurence stated that MID had several issues before it. First was to review bill impacts and address mitigation of those impacts, if needed. Second was to present its proposal to the ISO Board in June.

David Cohen asked if MID had prepared a summary of the difference between the ISO and MID proposals. Laurence responded that MID had one at one time, but did not have a current summary.

CDWR asked about the differences between using 1 NCP and 12 NCP. Laurence replied that the differences were philosophical (longer was better) and related to the litigation in the 2001 GMC (the ALJ preferred a longer period).

After the lunch break, Ben Arikawa gave a presentation on the cost components within each of the ISO's charges. This brought up a number of concerns, not all related to the functionalization or rate design. These were:

- What are the definitions of the cost categories?
- How are the Congestion Management costs in the ISO proposal were different than the current Congestion Management?
- How were MD02 costs assigned?
- What were the assignments of legal and regulatory costs?
- Were there any methods of directly assigning legal costs, ***e.g.***, through timesheets?
- How were external legal costs assigned?
- How were telecommunications costs assigned and what will telecommunications costs be next year under the new contract?
- What is the disposition of the land that the ISO purchased in 2000?
- What is the function of the Alhambra facility?

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This last question started a discussion of operations of the Alhambra personnel and the need for a backup control center. Jan Pritchard noted that a backup control center does not appear to be cost-efficient until you need it.

At the conclusion of this discussion, the ISO began a presentation on options for recovery of Customer Services costs. The presentation contained a brief summary of the annual fees assessed by other ISOs to their customers and a recounting of the California ISO's thinking in developing the billing determinant for Customer Services.

There was a long discussion of the amount of the California ISO's Customer Service costs relative to other ISOs. However, as there is no standardized FERC accounting for ISOs, it would be difficult to determine if the California ISO's costs were "out of line" with other ISOs.

There were several questions concerning the cost drivers underlying Customer Services. Market transactions may be a large driver. However, market transactions would not cover all drivers.

IEP asked if a tiered approach to the customer service charge could be implemented. The ISO had thought of such an approach, but could not develop an implementation that it thought was non-discriminatory and understandable.

There were also questions about why the ISO chose to break out Customer Service costs separately as no other ISO had done so.

At this point, the ISO suggested a separate conference call during which parties could suggest options. The ISO requested that parties submit written proposals concerning the recovery of Customer Service costs, including the rationale for fixed vs. volumetric recovery. This conference call would be scheduled later.

Three meetings or conference calls were scheduled over the next month. The first was a meeting on May 12 in which the ISO and MID would provide updated proposals and the ISO would response to the various requests made during this meeting. A meeting was also scheduled for June 4 prior to the next Board of Governors meeting to give the participants an opportunity to provide input into any discussion to the Board.

The CPUC requested that a conference call be scheduled for May 19.

The public portion of the meeting ended and the confidential portion of the meeting began.

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